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Volume II—Comparison and Evaluation of Results

National Aeronautics and Space Administration
Lewis Research Center

August 1984

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MINS: / COGENERATION/ ENERGY CONSERVATION/ ENERGY CONSUMPTION/ PHOSPHORIC ACID FUEL CELLS

ABA: B.W.

ABS: CTAS compared and evaluated various advanced energy conversion systems that can use coal or coal-derived fuels for industrial cogeneration applications. The principal aim of the study was to provide information needed by DOE to establish research and development (R&D) funding priorities for advanced-technology systems that could significantly advance the use of coal or coal-derived fuels in industrial cogeneration. Steam turbines, diesel engines, open-cycle gas turbines, combined cycles, closed-cycle gas turbines, Stirling engines, phosphoric acid fuel cells, molten carbonate fuel cells, and thermionics were studied with technology advancements appropriate for the 1985-2000 time period. The various

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National Aeronautics and Space Administration
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CONTENTS

COGENERATION TECHNOLOGY ALTERNATIVES STUDY (CTAS)

VOLUME II - COMPARISON AND EVALUATION OF RESULTS

National Aeronautics and Space Administration
Lewis Research Center
Cleveland, Ohio 44135

1.0 SUMMARY

Gerald J. Barna and Gary D. Sagerman

The Cogeneration Technology Alternatives Study (CTAS) was undertaken by NASA for the Department of Energy (DOE). It was a broad screening study aimed at providing technical and economic comparisons needed by DOE to help guide research-and-development (R&D) funding for advanced energy conversion systems. The advanced energy conversion systems studied were those that could significantly advance the use of coal or coal-derived fuels in industrial cogeneration applications, where electricity and process heat are simultaneously produced at the industrial site.

Project management responsibilities for CTAS were delegated to NASA's Lewis Research Center. Most of the data were obtained through two contracted studies of similar scope performed by industrial teams led by the General Electric Co. and the United Technologies Corp. In addition to managing the overall study, Lewis also performed independent analyses and a comparative evaluation of the advanced energy conversion systems on the basis of study results. Selected investigations were also performed by the Jet Propulsion Laboratory in support of Lewis. This report describes the overall CTAS effort, presents a detailed comparison of the systems studied by the two CTAS contractor teams for the various industrial plant and conversion system combinations, and identifies, on the basis of the Lewis evaluation of overall study results, the most attractive advanced energy conversion systems that use coal or coal-derived fuels for industrial cogeneration.

Nine types of energy conversion system were examined in CTAS:

(1) Steam turbines
(2) Diesel engines
(3) Open-cycle gas turbines
(4) Combined gas turbine/steam turbine systems
(5) Stirling engines
(6) Closed-cycle gas turbines
(7) Phosphoric acid fuel cells
(8) Molten carbonate fuel cells
(9) Thermionics

Each system type was studied with a variety of fuels, system configurations, and levels of technological advancement appropriate for implementation between 1985 and 2000. In addition, for the steam turbines, diesel engines, open-cycle gas turbines, and combined cycles, technology levels and fuels representative of today's commercially available equipment were included to serve as a baseline for evaluating the advantages of advanced systems. Emphasis in the

study was on the use of high-sulfur coal, minimally processed liquid fuels made from coal, and low- or intermediate-Btu gas produced in onsite, integrated coal gasifiers.

The systems were examined for potential application to approximately 85 industrial processes selected primarily from the six highest energy-consuming U.S. industry groups, namely, chemicals, metals, petroleum refining, paper, cement and glass, and foods. The specific potential applications selected from these industry groups included manufacturing industries, which account for about half of the energy used by industry today. The manufacturing applications encompassed a wide diversity in the electricity required, in the relative magnitude of the electrical and thermal demands, and in the temperature of the hot water, steam, or direct heat needed for the process.

The systems were matched to the process requirements by using two basic strategies. In the first the energy conversion system was sized to meet the electrical demand of the process plant and, where required, a supplementary furnace was used to provide additional thermal energy. In the second strategy the system was sized to meet the thermal requirements of the process and, where required, electricity was either purchased from a utility (import) or sold to a utility (export), depending on whether the systems produced more or less electricity than was needed at the site. Different systems and strategies matched different manufacturing applications well, depending on the characteristics of both the process and the energy conversion system. The potentially attractive applications found for each advanced system were documented as part of the study.

Over 6000 cases were calculated for the various combinations of energy conversion systems, configurations, fuels, matching strategies, and industrial process plants. Included in the calculations were the fuel energy saving, annual cost saving, emissions saving, and the rate of return on investment for the cogeneration systems - all relative to the noncogeneration situation of purchasing the electricity needed at the site from a utility and providing the thermal energy required with an onsite boiler. The cost saving calculated included fixed capital charges, fuel costs, operating and maintenance costs, and the cost (import) or credit (export) for electricity bought or sold. The emissions saving was relative to the total emissions at the plant site and at the utility. Emissions at the plant site alone were also calculated for the cogeneration cases and the noncogeneration situation. Although the emphasis in the study was on the "plant basis" analyses just described, the contractors and Lewis also extrapolated potential energy savings and other benefits for each system to a "national basis" in order to examine the relative attractiveness of the various advanced systems from a national perspective as well. This allowed the percentage saving on a plant basis to be "weighted" by using the national energy consumption for each process included in the study. The contractors then extrapolated results beyond the specific processes studied in order to estimate benefits for the entire manufacturing sector of industry.

Results for the advanced energy conversion systems were then compared with each other and with results for cases using current commercially available technology, on both a plant basis and a national basis. From Lewis' evaluation of the study results attractive advanced energy conversion systems were identified and placed into two groups as shown in table 1-1. The advanced systems identified as the most attractive showed the widest applicability to the spectrum of process plants included in the study.

To illustrate the results obtained for these attractive advanced systems, ranges of results are presented here for nine representative industrial processes studied in common by both contractors and used by Lewis in a detailed screening of plant-basis results. The ranges shown are only for the attractive applications within the subset of the nine industrial process plants:

(1) Fuel energy saving, 14 to 44 percent - all attractive systems

(2) Levelized annual operating cost saving:
19 to 42 percent - attractive coal-fired systems
8 to 27 percent - attractive systems using coal-derived liquid fuels

(3) Emissions saving:
72 to 91 percent - molten carbonate fuel cells
6 to 24 percent - GE results for gas turbines and combined cycles using coal-derived liquid fuels
35 to 57 percent - UTC results for gas turbines and combined cycles using coal-derived liquid fuels
25 to 54 percent - all other attractive systems

(4) Return on investment:
17 to 54 percent - the "most attractive advanced systems"
11 to 20 percent - the "attractive advanced systems"

(Refer to section 2.5 for definition of terms.)

The higher cost saving for the attractive coal-fired advanced systems as compared with the attractive systems using coal-derived liquid fuels was primarily due to the difference in the fuel costs for the cogeneration systems. The molten carbonate fuel cell systems had the highest emissions saving of the attractive systems because of the higher quality fuel used and the characteristics of that system. In fact, the onsite emissions of some fuel cell systems were estimated to be lower than in the noncogeneration situation even though more fuel is used at the site in cogeneration. The differences in emissions saving between the GE and UTC results for open-cycle gas turbines and combined cycles fired by coal-derived liquid fuels resulted primarily from different assumptions for the oxides-of-nitrogen (NO_x) reductions achievable, particularity in NO_x from the high fuel-bound nitrogen in the coal-derived residual fuel.

In addition to the screening of advanced systems on a plant basis, Lewis evaluated the potential relative national savings of the advanced systems in the specific industries studied. The approach used by Lewis involved extrapolating the contractors' plant-basis results to the new and replacement markets between 1985 and 1990 for each of the specific processes included in the contractors' studies. Potential national energy savings and other benefits were estimated by assuming 100 percent implementation in each industry where a "hurdle" return on investment (ROI) was exceeded. This hurdle ROI was varied parametrically to investigate the sensitivity of potential national savings to required ROI. The national-basis evaluations made by Lewis using this approach were generally consistent with and reinforced the identification of attractive systems that was based on the results of Lewis' plant-basis screening.

Typically, allowing the export of electricity increased the potential national energy saving by a factor of 1.5 to 2.5. In many cases with exported

electricity, 2 to 4 times more electricity was generated than was needed at the site. In other cases, 5 to 10 times more electricity was generated than was needed at the site. In these cases the utility and industry must closely coordinate the generation of electricity.

In addition to comparing the advanced systems with each other, national-basis results for all of the advanced systems assumed to be available were compared with results limited to those systems employing only current commercially available technology. Depending on the ROI hurdle specified, results for the advanced systems showed a 40 percent to more than 80 percent energy saving over the results for cogeneration systems using only current commercially available technology. Associated with the potential increase in national energy saving was a 20 percent to more than 50 percent reduction in emissions, depending on the hurdle ROI and the assumptions for technological advances to reduce emissions. In many applications the advanced systems showed higher ROI as well. Finally, the advanced energy systems (which were based on the use of coal or coal-derived fuels) showed good applicability to those industries now consuming large amounts of petroleum oils. This indicates a potential for displacing the use of oil as well as for saving energy.

In reading this report it is important to keep in mind that the objective of the study was to provide technical and economic comparisons and evaluations of advanced energy conversion systems for industrial cogeneration rather than to address the benefits of cogeneration itself. No attempt was made to propose solutions to institutional, regulatory, or market barriers that could limit the ultimate implementation of cogeneration. Furthermore, the evaluations made apply only to industrial cogeneration applications. Different relative attractiveness could very well be found for other applications such as utility power-plants (electricity only), commercial and residential total energy systems, or institutional and government installations, where the technical and economic requirements can be significantly different from those used in this study.

TABLE 1-1. - ATTRACTIVE ADVANCED ENERGY CONVERSION SYSTEMS

Most attractive advanced systems	
Steam turbines	Coal/atmospheric-fluidized-bed furnace (AFB) Coal/pressurized-fluidized-bed furnace (PFB)
Open-cycle gas turbines	Coal-derived liquid fuel, residual grade
Combined cycles	Coal-derived liquid fuel, residual grade
Attractive advanced systems	
Open-cycle gas turbines	Coal/AFB Coal/PFB Integrated coal gasifier
Closed-cycle gas turbines	Coal/AFB
Molten carbonate fuel cells	Integrated coal gasifier Coal-derived liquid fuel, distillate grade

2.0 <u>INTRODUCTION</u>

Gerald J. Barna, Gary D. Sagerman, and John W. Dunning

2.1 BACKGROUND

Cogeneration is broadly defined as the simultaneous production of electricity (or shaft power) and thermal energy. When cogeneration is used, a significant saving in fuel energy can result because thermal energy, wasted when generating only electricity, is recovered and used. Recently, cogeneration has seen relatively limited use in the United States because fuel has been cheap and readily available. However, in the light of diminishing petroleum reserves and the resulting rising fuel and electricity prices, the application of cogeneration concepts may have the potential for significant national benefits in the future, especially if coal or alternative fuels can be utilized.

The Department of Energy (DOE) is responsible for the advancement of cogeneration technology through the use of both current- and advanced-technology energy conversion systems. In line with the latter responsibility the Cogeneration Technology Alternatives Study (CTAS) was undertaken by NASA for DOE under the authority of interagency agreement DE-AI01-77ET13111. The CTAS was a broad screening study that compared and evaluated selected advanced energy conversion systems appropriate for use in industrial cogeneration systems between 1985 and 2000. Industrial cogeneration in the context of this study refers specifically to the simultaneous onsite production of electricity and useful thermal energy to meet representative industrial plant requirements. A variety of potential industrial applications were selected - primarily from high-energy-consuming industries in the United States. The principal aim of the study was to provide the DOE with information needed to establish research-and-development (R&D) funding priorities for advanced-technology energy conversion systems that could significantly advance the use of coal or coal-derived fuels in industrial cogeneration applications.

2.2 OBJECTIVES

The specific objectives of the overall CTAS effort were

(1) To identify and evaluate the most attractive advanced energy conversion systems, for implementation in industrial cogeneration systems between 1985 and 2000, that could permit increased use of coal or coal-derived fuels

(2) To quantify and assess the advantages of using advanced systems in industrial cogeneration

CTAS was concerned exclusively with providing technical and economic comparisons and evaluations of advanced systems as applied to industrial cogeneration rather than with evaluating the merits of the cogeneration concept.

2.3 OVERALL SCOPE AND METHODOLOGY

At the request of DOE, nine types of energy conversion systems were evaluated in CTAS:

(1) Steam turbines
(2) Diesel engines
(3) Open-cycle gas turbines
(4) Combined gas turbine/steam turbine cycles
(5) Stirling engines
(6) Closed-cycle gas turbines
(7) Phosphoric acid fuel cells
(8) Molten carbonate fuel cells
(9) Thermionics

Each type of system was examined with a variety of fuels and over a range of parameters and levels of technological advancement that could be made available for implementation between 1985 and 2000. In addition, for the steam turbine, diesel engine, open-cycle gas turbine, and combined-cycle systems, cogeneration results for technology levels and fuels representative of current commercially available equipment were estimated in order to serve as a baseline for evaluating the advantages of advanced systems. Emphasis in the study was on the use of high-sulfur coal, minimally processed liquid fuels made from coal, and low- or intermediate-Btu gas made from coal in onsite gasifiers integrated with the cogeneration system.

The systems were examined in cogeneration applications in a wide variety of representative industrial process plants selected from the highest energy-consuming industries. The process plant applications were primarily from six major industry groups: namely, chemicals and allied products; primary metal industries; petroleum refining and related industries; paper and allied products; stone, clay, glass, and concrete products; and food and kindred products. These six major industry groups accounted for nearly 80 percent of the energy required to provide electricity and heat to the manufacturing sector of U.S. industry in 1975.

Figure 2.3-1 shows the organizational approach used in the study. The study was managed by NASA's Lewis Research Center for DOE's Division of Fossil Fuel Utilization. Most of the data in the study were developed in the two contracted studies performed by industy teams led by the General Electric Co. and the United Technologies Corp. Because of the great diversity of system types and industrial applications, each contractor team consisted of a prime contractor responsible for study management and a number of other organizations, including divisions of the prime contractor's organization and subcontractors. This was done to bring to bear on the study expertise in all of the elements necessary to establish the technical, economic, and environmental characteristics of complete cogeneration systems. The principal participants in the two contracted studies are identified in table 2.3-1.

The two contractor efforts were conducted independently and had essentially the same scope. Some common ground rules were established by NASA in consultation with DOE for use in the studies so that the results from the two contractor efforts could be more readily compared. An essential feature of the CTAS approach allowed each contractor to select design concepts and parameters, system configurations, technological assumptions, and the like that were consistent with the industrial experience and judgment of the various team members. It was anticipated that differences in contractor results would occur and furthermore that these differences could be both valid and instructive in evaluating the merits of the various advanced energy conversion systems studied.

The Jet Propulsion Laboratory (JPL) supported Lewis in CTAS in a number of areas, which included conducting a survey of potential industrial applications for cogeneration and providing data on regional differences that could affect study results. Lewis, in addition to managing the overall study, performed in-house analyses to supplement and complement the contractor effort, to provide an understanding of the differences between contractor results, and to evaluate the study results.

The overall methodology employed in CTAS is shown in figure 2.3-2. Between the two contractors over 150 combinations of fuels, energy conversion systems, design options, and parameter variations were input into the synthesis of cogeneration systems for potential application to approximately 85 representative industrial process plants. Using different strategies for matching the energy conversion system to the process plant requirements, the contractors calculated plant-basis cogeneration results for more than 6000 cases. These plant-basis results included calculation of fuel energy saving, annual energy cost saving, and emissions reductions as compared with the noncogeneration situation of purchasing electricity from a utility and providing thermal requirements with an onsite boiler. From these results attractive cases for each of the nine types of energy conversion systems were examined by the contractors in a more detailed economic analysis that included calculation of return on investment and the sensitivity of results to changes in the economic ground rules. Sensitivity of results to changes in ground rules was also studied by Lewis. Emphasis in the study was on these plant-basis calculations. However, potential benefits such as energy and emissions savings were also estimated on a national basis by each contractor in a first-order manner for each system as another input into the evaluation of the relative merit of the various concepts. Lewis independently estimated relative savings for the various systems on a national basis by using the contractors' plant-basis results as input data. The plant-basis and potential national benefits were then used by each contractor and by Lewis to compare and evaluate the advanced systems for application to industrial cogeneration.

2.4 PURPOSE OF REPORT

The purposes of this detailed CTAS report are

(1) To present the results of the CTAS effort, focusing primarily on the results of the Lewis in-house comparison, evaluation, and analysis of study results

(2) To identify the most attractive advanced energy conversion systems for industrial cogeneration based on a Lewis evaluation of study results. A complete listing of the CTAS reports is provided in appendix A.

While reading this report it is important to keep in mind that the objective of the CTAS effort was to compare and evaluate advanced energy conversion systems rather than to evaluate the merits of the cogeneration concept itself. Since CTAS represents a very broad screening effort, more emphasis was placed on the relative comparisons among systems than on the absolute values of the various technical and economic results calculated. More detailed studies of the attractive systems are required to more precisely define the best configurations and to investigate those technical, economic, and other aspects of implementing advanced technology in industrial cogeneration that were not within the scope of this broad screening effort.

Section 3.0 defines the cogeneration concepts and options studied, identifies the industrial process plants included in the study and summarizes their characteristics, describes the energy conversion system variations examined, and provides some perspective on the overall scope of the CTAS effort. Section 4.0 describes the common ground rules established by NASA for the study and the major assumptions specific to each contractor's effort, defines some of the parameters used to evaluate the advanced energy conversion systems, and presents the screening approach used by Lewis in evaluating those systems. Section 5.0 comprises the bulk of the report. It details the Lewis comparison and evaluation of the contractors' assumptions and results. The section is divided into subsections, each dealing with a single type of energy conversion system. Section 6.0 summarizes the plant-basis and national-basis results estimated by Lewis, identifies the most attractive advanced systems based on the Lewis evaluation of study results, and discusses some of the benefits of advanced cogeneration systems. Section 7.0 contains concluding remarks and some additional perspectives on CTAS results.

Appendix A identifies the reports published as part of CTAS. The list includes NASA, JPL, and contractor reports. Appendix B discusses the methodology used in the economic evaluation and presents a comparison of economic parameters used by the contractors. Appendix C presents the details of the economic ground rules used in this study. Appendix D gives the results of a parametric cogeneration analysis and discusses the evaluation parameters used in the study. Appendix E discusses the sensitivity of the plant-basis results to changes in electricity and fuel prices.

2.5 DEFINITION OF TERMS

AR heat recovery factor, the heat recovered divided by the total heat rejected

$$AR = \frac{(\text{Heat})_{\text{recovered}}}{(\text{Heat})_{\text{rejected}}} = \frac{Q_{\text{recovered}}}{Q_{\text{rejected}}}$$

$$Q_{\text{rejected}} = \frac{(1 - \eta_e)\ P}{\eta_e}$$

where η_e is system electrical efficiency and P is electric power output. Hence

$$AR = \frac{Q_{\text{recovered}}}{P(1 - \eta_e)/\eta_e}$$

BOP balance of plant

C incremental investment, the difference in capital investment required between a cogeneration system and a conventional energy system

CSR cost savings ratio equal to the levelized annual energy cost saving ratio (LAECSR)

EMSR emissions saving ratio, a measure of the reduction in cogeneration system exhaust emissions as compared with emissions from a noncogeneration system that meets site requirements

$$\text{EMSR} = \frac{(\text{Emissions})_{\text{noncogen}} - (\text{Emissions})_{\text{cogen}}}{(\text{Emissions})_{\text{noncogen}}}$$

Emissions include sulfur dioxide, oxides of nitrogen, and particulates at the utility and industrial sites. This ratio can be calculated for the sum of these three constituents or individually for each constituent.

FESR fuel energy saving ratio, a measure of cogeneration system fuel energy saving as compared with the fuel refined to meet site requirements without cogeneration

$$\text{FESR} = \frac{(\text{Fuel energy})_{\text{noncogen}} - (\text{Fuel energy})_{\text{cogen}}}{(\text{Fuel energy})_{\text{noncogen}}}$$

The fuel energy equals the sum of the onsite fuel, the purchased (over the fence) fuel, and the fuel equivalent of electricity purchased from a utility to meet the needs of the site operation.

IR investment ratio, the ratio of the capital investment required for a cogeneration system to the capital investment required for a conventional energy system

LAEC levelized annular energy cost, the minimum constant net revenue required each year of the life of the plan to pay expenses for energy, namely for electricity and process heat. The LAEC is a sum of fixed and variable costs, including fixed capital charges (cost of debt and return on equity) for fuel costs, operating and maintenance costs, costs for purchased electricity (if required), credit for sale of electricity (if excess is generated).

LAECSR levelized annual energy cost saving ratio, a measure of cogeneration system cost saving as compared with costs required to meet site requirements without cogeneration

$$\text{LAESCR} = \frac{(\text{LAEC})_{\text{noncogen}} - (\text{LAEC})_{\text{cogen}}}{(\text{LAEC})_{\text{noncogen}}}$$

Payback inverse of ROI is an approximation of the payback period

ROI return on investment, the rate that equates the present value of all future cash flows with the initial capital investment

$$\text{ROI} = \frac{\text{Annual return}}{\text{Capital investment}}$$

The ROI's were calculated on the basis of the incremental investment required for a cogeneration system relative to noncogeneration and on an inflation-fee, after-tax basis. Cash flows were incremental values relative to noncogeneration.

SOA state of the art

TABLE 2.3-1. - CTAS CONTRACTOR TEAMS

	General Electric Co.	United Technologies Corp.
Program management	GE Energy Technology Operation	UTC Power Systems Division
Energy conversion systems	GE Internal Divisions Delaval, Inc. Institute of Gas Technology North American Phillips Corp.	UTC Internal Division Aerojet Energy Conversion Co. Bechtel National, Inc. Cummins Engine Co., Inc. Delaval Turbine and Compressor Division Dr. Phillip Myers, consultant Mechanical Technology, Inc. Rasor Assoc. Sulzer Brothers, Ltd. Westinghouse Electric Co.
Industrial processes	GE Internal Divisions Dow Chemical Co. General Energy Assoc. Kaiser Engineers, Inc. J. E. Sirrine	Gordian Assoc.

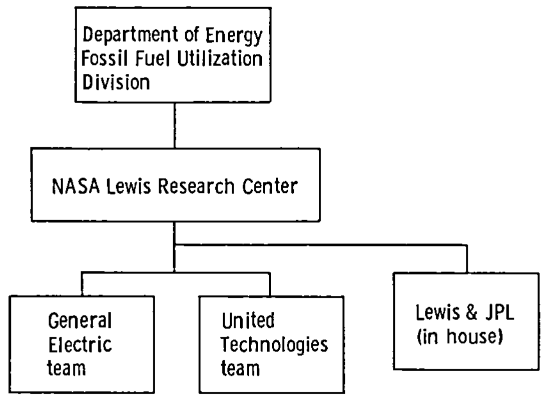


Figure 2.3-1. - CTAS organization.

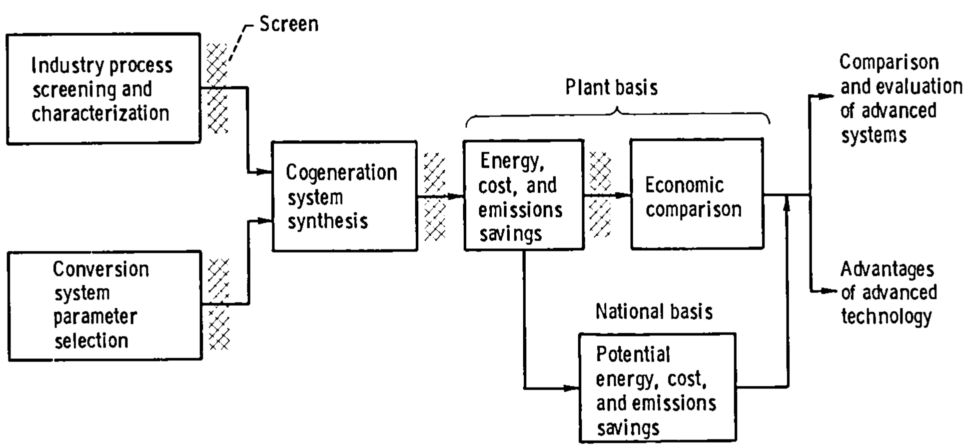


Figure 2.3-2. - CTAS methodology.

3.0 STUDY SCOPE

This section presents the information necessary to appreciate the context in which the advanced energy conversion systems were studied and the scope of the analyses performed for the various systems. Section 3.1 introduces the various options and strategies considered in CTAS for matching energy conversion systems with industrial processes in cogeneration configurations and, in doing so, defines some of the concepts and terms used frequently in this report. Section 3.2 identifies the industrial process plants included in the study and summarizes the data for these representative applications. Section 3.3 describes the configurations and ranges of design and operating parameters investigated for the various energy conversion systems. Finally, section 3.4 provides perspectives on the limitations in the scope of the CTAS effort.

3.1 INDUSTRIAL COGENERATION OPTIONS AND STRATEGIES

Gary D. Sagerman

In CTAS it was important to establish an approach that would allow the many conversion systems with quite different characteristics to be compared on a consistent basis over a broad range of industrial process requirements. The approach selected for CTAS was to establish for each industrial process a baseline noncogeneration case against which all cogeneration systems, both current and advanced, were then compared.

The noncogeneration concept, which represents the approach currently used by most U.S. industrial plants to satisfy their requirements for electricity and process heat, is depicted schematically in figure 3.1-1. All electricity is purchased from a utility, and all process heat is produced by furnaces or boilers located at the plant site. Fuel used at the utility is assumed to be coal. The utility fuel is important for the calculation of emissions savings and fuel savings. Fuel for the onsite furnaces or boilers is, in general, purchased. The contractors independently determined the onsite fuel for the noncogeneration base case on the basis of their anticipation of future trends (section 4.2). In cases where combustible wastes or byproducts that could be used as fuel are available from the industrial process, they are, where appropriate, used in both the noncogeneration and cogeneration situations. The fuel energy requirements and emissions associated with the generation of electricity at the utility and the onsite production of process heat were calculated, along with the total cost to the industrial owner of satisfying the total energy requirements of the process in the noncogeneration case. These values then provided a base against which to evaluate the relative benefits of the various current and advanced cogeneration systems. Even though a number of the industrial processes considered in CTAS currently involve cogeneration to varying degrees, a noncogeneration case was established for every process in order to achieve a consistent comparison of energy conversion systems across all industries.

Two options or configurations can be considered when applying cogeneration to an industrial process: namely, topping and bottoming. In the topping cogeneration configuration, fuel is input to an energy conversion system located on an industrial plant site and generating electricity for use in the plant. Waste heat from the conversion system is recovered and used to provide

heat in some form to the industrial process. In the bottoming configuration, fuel is burned in a furnace or boiler to provide the process heat required, and the waste heat from the process is used as the thermal input to an energy conversion system that generates electricity. Because of the program interests of the sponsoring DOE division the emphasis in CTAS was on the topping option. And, although UTC did examine a few bottoming applications, this report presents results only for topping.

The most desirable situation in the case of a topping configuration would be when the electrical and recoverable thermal outputs from the onsite energy conversion system just match both the electrical and process heat requirements of an industrial plant. System designs employing a variable extraction steam turbine lend themselves more readily to achieving the desired electricity-to-recoverable-heat ratio than do designs using a fixed-geometry condensing steam turbine. In CTAS, because of the large number of conversion system types and the many diverse industrial processes being considered, it was necessary to establish a number of fixed system designs from which to select for each application so that the matching process could be computerized.

When an exact match of both electrical and thermal outputs cannot be achieved, a number of alternative strategies may be considered in matching a system to a plant. In CTAS the components required for a cogeneration system, including the energy conversion system, were assumed to be available in any required size within a range established by the contractors as reasonable for each of the respective components. On the basis of this assumption the contractors used two basic matching strategies. The basic strategies that were considered are shown in figure 3.1-2. In what has been designated the "match electricity" strategy (fig. 3.1-2(a)) the energy conversion system is sized to meet the electrical demand of the industrial process. If the heat recovered from the conversion system is insufficient to meet the process requirement, a supplementary furnace is used on site to make up the deficit. If the heat recovered from the conversion system is greater than the process heat requirement, only enough heat is recovered to fulfill the process needs.

In the second basic sizing strategy, designated the "match heat" strategy (fig. 3.1-2(b)), the energy conversion system is sized such that its recoverable heat just matches the process heat requirement of the industrial plant. If the electrical output of the conversion system is not adequate to meet the plant requirement, additional electricity is purchased from a utility. On the other hand, if excess electricity is generated by the onsite conversion system, the excess is exported from the site and sold to the utility grid.

In addition to these two basic matching strategies, UTC also examined a third strategy designated the "maximum energy saving" strategy. This strategy was developed by UTC specifically for those cases where process heat was supplied to a plant at multiple temperatures. UTC established a "bin" system (section 4.2) for cataloging the plant process heat requirements and the recoverable heat available from the conversion systems. Five qualities (or "bins") of thermal energy were defined (140° F hot water, 300° F steam, 500° F steam, 700° F steam, and duct heat), and all plant requirements and conversion system capabilities were expressed in terms of these fixed bins. UTC set up a trade-off system that would enable them to select and size the system in such a way as to maximize the fuel energy saving achieved. Hence, the name "maximum energy saving" strategy. When only a single process heat temperature is required by a plant, the result for the maximum-energy-saving strategy was the

same as that for either the match-electricity or match-heat strategy, whichever resulted in the greater energy saving.

The match-electricity, match-heat, and, in the case of UTC, maximum-energy-saving strategies were used in calculating results for the various cogeneration systems examined. For the purposes of this report, however, the results of these strategies have been evaluated and displayed by Lewis in two sets. The first set includes only cases that do not produce more electricity from the cogeneration system than is required at the site and therefore do not sell any electricity to a utility (no power export allowed). The second set of results encompasses all cases, including those in which electricity is sold to a utility (power export allowed). The second set would also include match-heat strategies that import electricity. Although the energy saving from cogeneration with advanced systems is significantly higher if power export is allowed, the regulatory and institutional situation at the time the technical effort on the CTAS study was being conducted tended to discourage the export of electricity to the utility. It was therefore felt that presenting results with and without export allowed would be instructive. In the contractor reports results are presented by cogeneration strategy.

The reader should be aware that, since the completion of the CTAS technical effort, major changes in the regulatory environment concerning cogeneration regulations were enacted as part of The National Energy Act of 1978. This act essentially ensures a market at a "fair price" for excess electricity produced by cogenerators. Enactment of these rules might significantly increase the viability of strategies involving export of electricity.

3.2 INDUSTRIAL PLANT REQUIREMENTS

Gary D. Sagerman and Karl A. Faymon

The purpose of CTAS was to evaluate and compare advanced energy conversion systems for application to cogeneration systems in industrial process plants in the manufacturing sector of U.S. industry. The Office of Management and Budget classifies the manufacturing sector of industry under Division D of the Standard Industrial Classification (SIC) code. This division covers the wide diversity of activities included in the industry groups designated in the SIC two-digit codes 20 to 39 as listed in table 3.2-1. These 19 industry groups are broken down into over 450 product-oriented, four-digit subclassifications, many of which can be further broken down into individual industrial processes. To gather data for all of these industries would have required a significantly greater effort than was possible within the resources available for CTAS. Instead, the approach used was to select a smaller number of industrial process plants whose characteristics constituted a representative cross section of industrial plant requirements. These selected plants would act as a framework for the evaluation and comparison of the advanced systems. The results for these plants could then be used to determine benefits on a plant-site basis and could also be extrapolated to estimate potential national impacts.

The CTAS contractor teams selected the industrial plants to be considered in CTAS with guidance from NASA. To gain the knowledge and insights required to evaluate and coordinate the selection of process plants by the contractors, NASA conducted an independent survey and screening of the manufacturing industry. This effort was carried out by the Jet Propulsion Laboratory (JPL).

The JPL effort identified the major energy-consuming industries and examined the characteristics of those industries to establish criteria that could be used in selecting representative process plants for use in CTAS.

Obviously the magnitude of an industry's total energy consumption is an important criterion in determining where the most significant opportunities for cogeneration might be realized, since even modest benefits on a plant-site basis could provide major benefits on a national basis. The top 10 energy-consuming, two-digit industry groups from the manufacturing sector are shown in figure 3.2-1 along with the relative amounts of energy consumed and the number of four-digit subclassifications within each major industry group. The energy consumed in 1975 in the top 10 two-digit industry groups was approximately 88 percent of the total energy consumed in the entire U.S. manufacturing industry, with the top six industry groups accounting for approximately 77 percent of the total. Primary emphasis was thus placed on the top six two-digit groups. However, a number of the higher energy-consuming processes from the remainder of the top 10 industry groups were also included.

Other criteria that were considered important in the selection of representative plants included

(1) Plant process heat requirements
(2) Temperatures and form of process heat requirements
(3) Site-required power-to-heat ratios
(4) Load profile for electric, thermal, and mechanical energy needs
(5) Annual hours of operation
(6) Number of plants in the United States
(7) Evolutionary trends in process utilization

It was also necessary that a diversity of process requirements representing a broad spectrum of U.S. industry be considered. Applicability over a wide variety of process requirements would obviously be a desirable trait for an advanced conversion system to penetrate the marketplace.

Each CTAS contractor team independently gathered data on the characteristics of the processes within the manufacturing industry and, on the basis of their respective data, selected processes to be considered in their studies. The two-digit industry groups considered in CTAS and the processes selected from those groups by the contractors, on the basis of the above criteria and other qualitative factors, are discussed in the following paragraphs. The four-digit classifications represented by processes selected by UTC consume about 50 percent of the energy used in the manufacturing sector of U.S. industry. The four-digit classifications represented by the GE processes account for about 58 percent of the manufacturing industry energy consumption. The specific four-digit industries examined by each contractor are shown in table 3.2-2.

The diversity of process plant requirements represented by the selected processes is illustrated in figures 3.2-2 to 3.2-4. The process characteristics shown are the respective contractors' projections for process plants to the 1985-2000 time period. Figure 3.2-2 shows the site-required power-to-heat ratio plotted versus the plant electrical requirement. Plants with electrical requirements from 1 MW electric to about 300 MW electric, exhibiting power-to-heat ratios from 0.01 to nearly 4.0, are shown. A few processes with electrical requirements less than 1 MW electric and several with power-to-heat ratios outside the range of the ordinate of figure 3.2-2 were considered but were, in

general, found to be unattractive for cogeneration with the conversion systems being studied.

The temperature at which process heat is required is very important in matching energy conversion systems to industrial processes. The amount of recoverable heat available from many energy conversion systems is a strong function of the temperature at which process heat is required. The recoverable heat available from other systems is relatively insensitive to the temperature requirement over a rather wide range. The temperatures at which steam is required for the selected processes are plotted in figure 3.2-3 as a function of site-required power-to-heat ratio. Most requirements are for process steam between 250° and 500° F. A number of the processes also require hot water at 140° to 170° F, and several processes require direct heat. (Where practical, UTC configured their cogeneration systems to fulfill all process heat requirements; GE provided only steam and hot water requirements in their configurations.)

The annual hours of plant operation and the frequency of shutdown can have a significant effect on the economic attractiveness of installing a cogeneration system and on the relative attractiveness of various types of energy conversion systems. Most of the process plants considered in CTAS operate three shifts per day, 5 to 7 days per week (roughly 6000 to 8000 hr/yr), as shown in figure 3.2-4.

As indicated earlier, the SIC system classifies manufacturing and industrial plants in accordance with their products rather than the process employed or the plant size. Therefore individual plants producing similar products and included in the same four-digit industrial classification can, and do, have significantly different plant sizes and power and process heat requirements. In a number of cases both contractors examined plants from the same classification. The plants and processes examined by the contractors are described in the volumes on industrial process characteristics of their respective CTAS final reports. The process descriptions will not be repeated herein, but the similarities or differences between plants chosen by the two contractors from the same industry will be pointed out and discussed briefly.

3.2.1 SIC 20 - Food and Kindred Products

This industry group includes establishments that manufacture or process foods and beverages for human consumption and certain related products, such is manufactured ice, chewing gum, vegetable and animal fats and oils, and prepared feed for animals and fowls. SIC 20 includes 46 four-digit subclassifications; the six examined in CTAS are shown in table 3.2-3. The characteristics of the plants studied by the contractors are summarized in figures 3.2-5 to 3.2-7. Only the meat packing and the malt beverage industries were selected by both contractors. The requirements of the plants selected from these two industries are compared and discussed below.

3.2.1.1 Meat Packing

The meat packing plants considered by the two contractors are similar in process and product. Both are integrated plants and include a complete range of operations from slaughtering to the final packaging of meat products. The

plant selected by UTC is much larger than the GE plant and requires somewhat less energy per ton of product output. Such variations are not unusual and can be attributed to the mix of products, the methods of performing various operations, etc.

The GE plant is a single-shift operation, 5 days per week. The UTC plant operates two shifts a day, 6 days per week. Both plants require steam, hot water, and direct heat, although GE did not consider the direct-heat requirement in defining the thermal requirement for cogeneration. The major electrical load is refrigeration, which is required around the clock, 365 days per year. The differences between the plants are well within normal variations.

3.2.1.2 Malt Beverages

Both contractors selected plants engaged in the production of beer. The annual production of the plant selected by GE is approximately 1.6 times that of the plant selected by UTC. The GE plant requirements are based on a three-shift operation, 5 or 6 days per week, depending on the demand, for a total of 6600 hours per year. The UTC requirements are based on a plant operating continuously 7 days per week, for approximately 8500 hours per year. When this variation in operating hours is factored in, the output per operating hour of the GE plant is twice that of the UTC plant. The thermal energy per unit of product output for the two plants is nearly identical. The major difference between the two plants is in the electrical requirement. An identifiable contributor to this difference is the greater electrical requirement for refrigeration exhibited by the GE plant. This could indicate that the GE plant is located in a warm climate, which would also increase the electrical load for plant and office air conditioning. Other process-related differences could also contribute to the sizable variation in electrical load.

3.2.2 SIC 24 - Lumber and Wood Products, Except Furniture

This major group includes logging camps engaged in cutting timber and plywood, sawmills and mills engaged in producing lumber and basic wood materials, and establishments engaged in manufacturing finished articles made entirely or mainly of wood or wood substitutes. Although this particular two-digit industry group was not among the six leading consumers that were emphasized in CTAS, SIC 2421, which includes sawmills, consumes more energy than many of the individual processes in the chemical industry and the separate industries in the food and kindred products classification. The industries considered from the SIC 24 group are listed in table 3.2-4. The characteristics of the plants selected are shown in figures 3.2-8 to 3.2-10. From this group only sawmills were considered by both contractors. The plants considered from SIC 2421 are compared below.

Both contractors selected integrated sawmills that start with timber and turn out finished building lumber as their product. The process includes debarking, sawing, drying, and planing. The GE plant is about four times as large as the UTC plant in product, output, and electric energy usage. Although both plants carry out essentially the same process, there is a sizable difference between the thermal energy requirements reported. The thermal requirements of the specific plant described by GE do not agree with the national average requirement that GE reported. In this industry the specific methods and schedules used for performing the various operations can produce fairly

wide variations in energy requirements. However, the thermal requirement of the GE plant is less than half that of the UTC plant, which has requirements very near the national average reported by GE.

A large amount of the thermal energy required by sawmills is currently produced by using waste wood from their own operations as fuel. It would appear that, in order for a cogeneration system to be economically viable in this industry, it would also have to be able to make use of the waste wood fuel.

3.2.3 SIC 26 - Paper and Allied Products

This major industry group includes the manufacture of pulp from wood and other cellulose fibers and from rags; the manufacture of paper and paperboard; and the manufacture of paper and paperboard into converted products such as paper bags, paper boxes, and envelopes. This industry group is highly complex and diversified and employs a large number of manufacturing techniques for the production of more than 2000 primary products. In general, the same major steps are included in each process. However, a large number of alternative process techniques are used depending on the type and quality of paper being produced.

A significant amount of the energy used in this industry group is currently produced by using fuels that are byproducts of the processes (liquors from chemical pulping, bark, and other waste wood). A large amount of cogeneration is currently practiced in SIC 26, and on the average almost half of the electricity used in this industry group is currently generated on site.

The plants selected by the two CTAS contractors are listed in table 3.2-5. UTC identified their plants by the product. GE identified their plants by the pulping process used. It is possible to use different pulping processes for the same product or to make different products from the same pulping process. As a result, direct one-to-one comparisons are difficult. NASA reviewed the plant process and product descriptions furnished by the contractors for the plants studied from this industry group and found three types of plants for which the two contractors have relatively consistent characteristics. The product identification used by UTC is shown without parentheses and the pulping process identification used by GE is shown in parentheses.

All of the plants studied are integrated mills that start in most cases with the debarking of wood and include all of the steps required to produce the finished product. The characteristics of the processes studied are summarized in figures 3.2-11 to 3.2-13. In those cases where UTC identified steam requirements in two temperature bins, both are shown in figure 3.2-12. The requirements of the three types of plants identified by NASA as being studied by both contractors are compared and discussed below.

3.2.3.1 Newsprint

The total energy consumed per unit output, the temperature of the steam required, and the ratio of power to heat required by the newsprint-producing plants studied by the contractors are quite similar. The GE plant is considerably smaller and requires slightly more electric and thermal energy per ton of

output. UTC identified a requirement for large quantities of hot water for pulp wasting; this requirement is, in general, satified by condensing the process steam after it had been used for other purposes. GE did not identify a hot water requirement, but it may be assumed that a similar requirement exists for their plant and is fulfilled in the same way.

Although the overall plant requirements, as identified, are quite similar, a closer look reveals some significant differences. The GE plant uses a mechanical pulping process that requires very little thermal energy but much electricity; the UTC plant uses a combination of mechanical pulping and chemical pulping that is thermal energy intensive. The GE plant calls for 95 percent of the total steam requirement to be supplied at high pressure for drying. The UTC plant uses low-pressure steam for drying and for liquor recovery and high-pressure steam (70 percent of total steam requirement) for the digesters in the pulping process. These differences are pointed out to illustrate the legitimate wide variations in energy requirements that can occur between plants within a given industry. Although the requirements for energy are very similar, the uses of that energy can be quite different.

3.2.3.2 Writing Paper

The writing paper plants selected by the two contractors for this industry are somewhat different in size (the GE plant produces 1.7 times the output of the UTC plant), but they may have the most similar requirements of any of the industries considered in common by the two CTAS contractors. As in the case of the newsprint plants GE did not identify a requirement for hot water, but it may be assumed that such a requirement exists and can be satisfied by condensate from the process steam as was assumed by UTC for their plant. The other apparent difference in the two plants is in the pulping step. GE assumed that all required pulp is produced by the chemical Kraft process. UTC produces about 78 percent of the required pulp by the Kraft process and the remainder by a mechanical process. This difference results in a somewhat greater amount of electricity per ton of output being required by the UTC plant.

3.2.3.3 Corrugated Paper

The corrugated paper plants considered by the two contractors had some significant differences in their energy requirements. The plant studied by GE produces 600 tons per day of corrugating medium. The plant studied by UTC has a total output of over 2000 tons per day of corrugated containers. The UTC plant requires the production of about 700 tons per day of corrugating medium plus about 1600 tons per day of liner board. If the production of the corrugating medium is separated from the remainder of the UTC plant production, the UTC plant matches quite closely the requirements of the GE plant both in absolute and relative amounts of electric and thermal energy per ton of corrugating medium produced. Both plants use the neutral sulfite semichemical pulping process for the production of corrugating medium. The UTC plant uses unbleached pulp from the Kraft process for the production of liner board for the containers they produce.

The situation illustrated by these two plants once again points out the diversity of plants within a given industry and the sensitivity of the energy requirements to the product line.

3.2.4 SIC 28 - Chemicals and Allied Products

This industry group includes establishments producing basic chemicals and establishments manufacturing products by predominantly chemical processes. Altogether over 1000 inorganic and organic chemical products are produced within the industries listed in this group. There are several thousand highly interrelated production processes within this group, each uniquely tailored to achieve the precise characteristics desired in each product. The diversity of products and production processes and the variation in mixes of products from one plant to another make it difficult to define a set of energy requirements that represents the integrated plants in the chemical industry. The CTAS contractors chose to select a number of the most energy-consuming individual processes and examine them for cogeneration application. GE also postulated energy requirements for three sizes of integrated chemical plants without specifically identifying the processes to be included.

The processes that were selected from the chemical industry by the CTAS contractors are shown in table 3.2-6. The characteristics of the processes studied are shown in figures 3.2-14 to 3.2-16. In those cases where UTC identified steam requirements in two temperature bins, both are shown in figure 3.2-15. Note that plants were selected by both contractors from seven of the industries in this group. The characteristics of the plants selected from those seven industries are compared briefly.

3.2.4.1 Low-Density Polyethylene

The energy requirements of the low-density polyethylene plants defined by the two contractors are considerably different. The GE plant is nearly twice as large in terms of product output but requires only about 38 percent more electricity than the UTC plant. The UTC plant requires about 7.5 times as much thermal energy per ton of output as the GE plant. The resulting total energy consumption per ton of output of the UTC plant is approximately twice that of the GE plant. Sufficient details are not available from the contractors' descriptions of their plants to identify the reasons for the differences.

3.2.4.2 Nylon Fiber

Approximately 70 percent of the nylon produced in the United States is of the nylon 6,6 form. Both plants selected by the contractors produce nylon 6,6. The plants each produce approximately 150 tons per day of product. In the production of nylon 6,6 the specifics of the process and the product mix have a major impact on the amount of energy required and the relative amounts of electrical and thermal inputs. Sufficient details are not available, especially for the GE plant, to perform a detailed analysis of the differences. However, variations of the magnitude indicated by the contractors' data are not surprising.

3.2.4.3 Styrene Monomer

The two contractors reported on styrene monomer plants of comparable output level with roughly the same electrical requirement. The primary difference was in the quantity of process heat required. A major source of this differ-

ence lies in the fact that the GE plant uses ethylbenzene as a feedstock, while the UTC plant produces ethylbenzene on site and its energy requirements (almost totally thermal) for the ethylbenzene production are included in the plant process heat requirements. The direct-heat requirement reported by UTC was also identified by GE; but, consistent with their ground rules, it was not included in the process heat load that was considered for cogeneration.

3.2.4.4 Chlorine - Caustic Soda

The chlorine - caustic soda plants considered by the two contractors are similar in concept, both using the diaphragm cell process rather than the mercury cell process which, while more energy efficient, is falling out of favor largely because of the environmental problems associated with it. Both plants operate three shifts a day throughout the year. The primary difference in the requirements of the two plants is in the amount of high-pressure (80 to 100 psi) steam required for caustic soda evaporation. The UTC plant requires approximately 7500 pounds of steam per ton of chlorine produced; the GE plant requires approximately 4200 pounds of steam per ton of chlorine produced. The lesser steam requirement per unit output may be at best partly due to improved efficiency at large sizes since the GE plant is about 55 percent larger than the UTC plant. Of course, some variation from plant to plant is normally expected. Another apparent difference in the requirements, as defined by the contractors, is that GE indicated that the total steam requirement is at 338° F or less, while UTC showed the major steam requirement to be in the 500° F bin. In actuality the requirement of the UTC plant is for 90- to 100-psia steam, which at saturation conditions would be about 330° F. Under the UTC bin system, since this requirement was greater than 300° F, it was placed in the 500° F bin.

3.2.4.5 Styrene-Butadiene Rubber

The styrene-butadiene rubber plants selected by the contractors have the same level of product output, 350 tons per day. Both plants use the emulsion polymerization process, which is used in 80 to 90 percent of styrene-butadiene rubber production in the United States. The summary data presented by the contractors indicate a major difference in the relative electric and thermal requirements. However, the difference is primarily due to the UTC plant's refrigeration compressors and cooling-water pumps being driven by natural-gas-fired engines. The fuel for these engines was reported as a direct process heat requirement. In the GE plant these compressors and pumps are driven by electric motors and hence are included in the electrical requirement. Correction of this difference results in agreement well within expected plant-to-plant variations due to process and product stream differences.

3.2.4.6 Alumina

The alumina plants considered by both contractors use the Bayer process for the production of alumina. The plants are of approximately the same size in terms of product output. The electrical requirements are well within what would be considered normal variation. Although the power-to-heat ratios calculated by the two contractors are identical, the direct heat required for the calcination of the alumina is not included in the power-to-heat ratio calcu-

lated by GE although it is identified in their report as industrial process heat. The steam use in the GE plant is considerably greater per unit of product than that in the UTC plant. Although not specifically identified, this higher energy consumption could be the result of a difference in the bauxite raw material being processed. Process heat temperature levels specified by the contractor are consistent.

3.2.5 SIC 29 - Petroleum Refining and Related Industries

This major group includes establishments primarily engaged in petroleum refining, manufacturing of paving and roofing materials, and compounding of lubricating oils and greases from purchased materials. Within SIC 29 petroleum refining (2911) accounts for more than 95 percent of the energy use. Accordingly, this was the only industry considered from SIC 29 by the CTAS contractors. The petroleum-refining industry is a highly complex, multiproduct operation that uses many processes to convert crude oil into usable products. Each refinery is designed to use a specific range of crude oils and has some degree of flexibility to alter product yields. Petroleum refineries tend to be unique in the exact processes used and the specific product streams. As a result, there are large variations from plant to plant in the amount of energy required to refine a barrel of crude oil. One common trait of all refineries is that they require large amounts of thermal energy and relatively small amounts of electricity. This makes them prime candidiates for export of electricity to the utility grid.

3.2.6 SIC 32 - Stone, Clay, Glass, and Concrete Products

This major group includes establishments engaged in manufacturing flat glass and other glass products, cement, structural clay products, pottery, concrete and gypsum products, cut stone, abrasive and asbestos products, etc., from materials taken principally from the earth in the form of stone, clay, and sand. Most of the thermal energy required in this industry group is at very high temperatures (2200° F and above) and cannot be achieved through heat recovery from energy conversion systems. It is possible to recover heat from the processes and use it to generate electricity with a bottoming system such as a steam turbine or an organic Rankine system. The plants selected by the contractors from SIC 32 are shown in table 3.2-7.

The requirements identified by UTC and GE for the plants selected from the glass container and cement industries, which they both considered, are very similar. Both contractors identified the requirement for the direct use of fuel in burners to melt glass and to "burn" raw materials for cement making. None of the plants has a significant requirement for steam, hot water, or hot gases in the temperature range available from the conversion systems considered in CTAS. UTC made a limited assessment of the benefits that could be achieved through the recovery of waste heat from the processes for use in bottoming systems to generate electricity. GE was not able, within the resources available, to consider bottoming systems in their study.

The plant data gathered by the contractors can be found in their respective reports on industry characteristics and will not be discussed further herein.

3.2.7 SIC 33 - Primary Metal Industries

This major group includes establishments engaged in the smelting and refining of ferrous and nonferrous metals from ore, pig, or scrap; in the rolling, drawing, and alloying of ferrous and nonferrous metals; in the manufacture of castings and other basic products of ferrous and nonferrous metals; and in the manufacture of nails, spikes, and insulated wire and cable. This major group also includes the production of coke. This is a very energy-intensive industry group. The potential for both topping and bottoming cogeneration systems exists in this group. However, only topping systems were considered by the CTAS contractors for application to these industries. The plants studied by the two contractors are shown in table 3.2-8. The requirements of the plants are summarized in figures 3.2-17 and 3.2-19. The plants selected by both contractors from code 3312 (integrated steel) and code 3331 (copper refining) are compared and discussed in the following paragraphs.

3.2.7.1 Integrated Steel

The integrated steel mill studied by UTC has twice the annual output of the mill selected by GE. The absolute requirements for steam and electricity for the GE mill are, however, greater than those for the UTC mill. As a result the energy input in the form of steam and electricity per ton of product for the GE mill is over 2-1/2 times that for the UTC mill. The data provided by GE on their mill did not include sufficient detail on the specific operations and processes employed or the product mix produced to allow an assessment of the specific uses of the thermal and electric energy inputs. For example, GE did not specify whether the mill includes an oxygen production facility. The UTC mill does include an oxygen facility. If the GE mill requirements included an oxygen facility, much of the difference in the electrical requirements would be explained.

Note that the power-to-heat ratio reported by UTC for their integrated steel mill includes the consumption of coke in the blast furnace. This heat cannot be cogenerated and was not included in the power-to-heat ratio assigned by NASA.

In any case, the energy requirements of steel mills, like those of other industries, are strongly dependent on the processes used and the product mix. The general level of the requirements of the contractors' selected mills is consistent with expected variations.

3.2.7.2 Copper Refining

The plants selected by the two contractors in the copper industry are quite different, but all represent valid plants in the industry. GE defined several plants of different sizes and employing several different smelting processes. The UTC plant uses the Arbiter process, which is an advanced hydrometallurgical process that replaces both the conventional smelting and refining steps in the copper production process. The plants of the two contractors cannot be directly compared but again illustrate the diversity of requirements within specific industries.

3.3 OVERVIEW OF ENERGY CONVERSION SYSTEMS, FUELS, AND RANGES OF PARAMETERS

Gary D. Sagerman

3.3.1 Energy Conversion System and Fuel Combinations

The combinations of energy conversion system types and fuels or combustion approaches considered by each contractor are shown in table 3.3-1. The petroleum- and coal-derived fuels are listed either as distillate or residual grade. The coal-fired cases are separated according to whether the coal was fired in an atmospheric fluidized bed (AFB) or in a pressurized fluidized bed (PFB) with in-bed desulfurization; whether it was fired directly and first-generation lime or limestone scrubbers were used for flue gas desulfurization (FGD); or whether the system included an integrated low- or intermediate-Btu coal gasifier with fuel gas desulfurization.

Since the objective of the study was to examine advanced energy conversion systems using minimally processed fuels, cases that used a high-Btu gaseous fuel, either natural or coal derived, were not selected. Any conversion system could use such a fuel more easily than the fuels that were considered, and inclusion of such natural-gas-fired cases would not have significantly altered the overall conclusions of the study.

The combinations of energy conversion systems and fuels analyzed with state-of-the-art design parameters are footnoted in table 3.3-1. These combinations served as a baseline for the comparison with advanced-technology cases. Note that most of the cases that use a petroleum-based fuel are state-of-the-art systems. The use of coal or coal-derived fuels is emphasized for the advanced-technology cases. Any of the advanced-technology cases that use coal-derived fuels could also of course use a petroleum-based fuel, probably with some improvements in performance, emissions, and cost.

3.3.2 Energy Conversion System Parameters

For the combinations of conversion systems and fuels listed in table 3.3-1 a range of parameters or some variation in system configuration was studied. The ranges of parameters used for the advanced-technology cases are summarized in table 3.3-2 for each type of system. Those used for the state-of-the-art baseline cases are summarized in table 3.3-3.

3.3.2.1 Steam Turbines

For steam turbine systems the advanced technology studied was mainly concerned with the boiler. Both contractors studied advanced systems with coal-fired, fluidized-bed boilers to compare with the state-of-the-art cases shown in table 3.3-3. UTC included consideration of 1800 psig/1050° F throttle conditions, which are beyond current practice in the United States for small industrial turbines.

As indicated in these tables the contractors used different steam turbine approaches. GE chose a noncondensing turbine with back pressure corresponding to the average pressure of the process steam required on site. UTC chose a condensing steam turbine with single extraction.

3.3.2.2 Open-Cycle Gas Turbines and Combined Cycles

Both contractors assumed the use of coal-derived residual fuel for most of the liquid-fired, open-cycle gas turbine systems. GE analyzed advanced systems with turbine inlet temperatures of 2200° F with air-cooled turbine blades and 2600° F with water-cooled blades. UTC analyzed advanced systems with a turbine inlet temperature of 2500° F and air-cooled blades. GE included recuperated cycles that use distillate fuel. Both contractors considered combined-cycle configurations that use the same gas turbine inlet temperatures assumed for the simple cycles. Both also analyzed configurations with steam injection to the combustor, where the steam is generated in a heat exchanger in the gas turbine exhaust.

Both contractors included gas turbine systems with an integrated, entrained-bed gasifier and cold fuel gas cleanup. GE used a combined cycle configuration and an oxygen-blown gasifier for this case; UTC used a simple cycle and an air-blown gasifier. In addition, UTC included gas turbines with coal-fired PFB combustors and indirectly fired gas turbines with AFB combustors. In both these situations they assumed the use of air tubes in the fluidized bed, with the heated, pressurized air ducted to the turbine inlet.

As shown in table 3.3-3 both contractors studied state-of-the-art gas turbines that have a 2000° F inlet temperature and use distillate petroleum fuel. In addition, GE included a state-of-the-art gas turbine at 1750° F that uses residual petroleum fuel.

3.3.2.3 Diesel Engines

GE studied four-stroke-cycle, medium-speed diesels using distillate or residual fuel. UTC studied high-speed diesels using distillate fuel and a low-speed, two-stroke-cycle diesel using residual fuel or pulverized coal. Both contractors assumed the use of coal-derived liquid fuels for the advanced diesel configurations. The UTC coal-fired case assumed a floatation process for desulfurization (but no cost or performance penalty for this was included by UTC for this system). In the advanced version of the high-speed diesel, UTC assumed the use of ceramic parts in high-temperature areas in order to completely eliminate jacket coolant. GE assumed advancements including higher brake mean effective pressure (BMEP), reductions in losses to the jacket coolant, higher coolant temperatures, and larger unit sizes. Both contractors also assumed a reduction in NO_x emissions although in their judgment the reduction would not be enough to bring the diesel engine emissions down to the limits set for the study. GE also considered the use of an open-cycle steam heat pump integrated with the jacket-coolant water loop in order to produce useful process steam from this waste heat.

3.3.2.4 Closed-Cycle Gas Turbines

Both contractors studied 1500° F closed-cycle gas turbine systems with atmospheric-fluidized-bed, coal-fired furnaces. In addition, UTC analyzed a 2200° F closed-cycle gas turbine system with a residual-fueled furnace containing ceramic heat exchangers. Both contractors included recuperated and unrecuperated cycles. In a cogeneration application an unrecuperated cycle would allow recovery of a greater fraction of waste heat as steam, which is

the dominant form required by the processes studied. The electrical efficiency is of course lower for the unrecuperated version. Also, to improve heat recovery at the expense of some loss in electrical efficiency, UTC considered cases with 190° and 300° F compressor inlet temperatures rather than the lower temperatures that would be more appropriate for power generation only.

3.3.2.5 Stirling Engines

As indicated in table 3.3-2 both contractors studied Stirling engines that use helium as the working fluid. In the liquid-fired case GE assumed that the heater-head tubes are located directly in the combustion zone. In the coal-fired case they used an intermediate helium gas loop to transfer heat from the pulverized-coal furnace to the engine heater-head tubes. GE did not use an AFB because they considered the temperature difference between the nominally uniform 1550° F fluidized bed and the selected 1470° F engine heater tube surfaces to be too small to be practical for such a gas loop. UTC did use an AFB furnace, but their engine configuration is much different. They studied a two-stage configuration with heat input to the engine at the peak value shown in table 3.3-2 and at nominally 500° F. They therefore used an intermediate air heat-transfer loop that exits the AFB at 1500° F, or the liquid-fueled furnace at 1800° F, and returns at 500° F.

Most of the process heat provided by the Stirling engine as configured in the UTC study is 500° F steam generated by using heat transferred from the intermediate air loop between the high-temperature input to the engine and the lower temperature input to the engine. Hot water at 140° F is obtained from engine heat rejection. GE, however, obtains most of their process heat in the form of steam from the engine by raising the heat rejection temperature. They obtain a smaller amount of steam from the furnace loop in order to avoid either the use of a high-temperature air preheater or high stack losses.

3.3.2.6 Phosphoric Acid and Molten Carbonate Fuel Cells

UTC studied only pressurized phosphoric acid fuel cells; GE considered only atmospheric cells. Both contractors used a conventional steam reformer for the fuel processing. UTC also considered an advanced adiabatic reformer to produce the hydrogen-rich gas required. The adiabatic reformer, unlike the steam reformer, uses neither a separate combustion of fuel nor heat transfer to the gasification reaction zone through the heat-exchanger surface. Instead, all of the fuel together with air and steam is mixed and reacted in the presence of a nickel catalyst. In one design option with the adiabatic reformer UTC uses the cathode exhaust, which contains unreacted oxygen and water vapor from fuel oxidation, as an input to the reformer instead of separate air and steam flow. This allows production of a larger amount of steam for process use.

In the high-temperature fuel cell cases UTC uses a configuration in which heat is removed from the molten carbonate fuel cell stacks by recirculating anode gas. GE uses recirculated cathode gas for the liquid-fueled case and excess cathode air for the integrated-gasifer case. Both used an entrained-bed, air-blown gasifier with cold-gas desulfurization in the coal-fired case. In the liquid-fueled case both GE and UTC used an adiabatic reformer.

3.3.2.7 Thermionics

As indicated in table 3.3-2, for the thermionic system GE assumed the use of planar, modular arrays of small converters lining the surfaces of the furnace. UTC used what is known as the THX approach, which involves larger converters mounted on large heat pipes, with the heat pipes extending into the furnace.

The two sets of emitter-collector temperatures shown in table 3.3-2 for GE are used for temperature staging within the furnace. GE used air to cool the collectors and then used this 1000° F air in the furnace for combustion. In UTC's case the collectors are steam cooled. In the UTC configuration the combustion air is heated by using furnace exit gases. They examined a 2200° F air preheat with a ceramic heat exchanger and a 1000° F air preheat with a metallic heat exchanger. The higher collector temperature shown in table 3.3-2 is used to generate steam turbine throttle steam in the UTC configuration that includes the bottoming cycle. The lower temperature collector is used in the configuration without a bottoming cycle, where only process steam is generated.

3.4 LIMITATIONS OF SCOPE

Gary D. Sagerman

The primary consideration in setting the scope of CTAS was to enable the advanced energy conversion systems studied to be compared and evaluated for industrial cogeneration applications. The potential process plant applications included in the study convert a large fraction (i.e., 50 percent) of the energy used by industry and include a wide diversity of process requirements. This enables valid and meaningful comparisons of the advanced systems to be made both for representative plants and on a national basis. Of course, not all applications could be included and other potentially attractive applications may exist. Furthermore, although process requirements for each application are those projected by the contractors for the 1985-2000 time period, changes in processes to make them more amenable to cogeneration were not considered in the study.

A wide, but certainly not exhaustive, range of advanced energy conversion system configurations and parameter variations was studied. More optimum configurations than those studied probably exist, particularly for those systems not previously studied for industrial cogeneration applications. However, it is believed that for the purposes of the study enough options were considered for each system to enable the relative merits of the various types of systems to be evaluated. More-detailed studies are required for the attractive systems to more precisely define the best configurations and to investigate those technical, economic, and other aspects of cogeneration that are beyond the scope of the CTAS effort.

Many institutional, regulatory, and market considerations will affect the ultimate implementation and acceptance of industrial cogeneration either with current or advanced systems. Although these considerations were recognized, no attempt was made in the study to provide solutions to any institutional or regulatory problems that may exist. Rather, where possible, results are presented in a way that can provide useful information to those charged with the responsibility for addressing these issues.

Finally, the study was concerned only with industrial cogeneration at individual plant sites. The evaluations of the systems therefore apply only to that application, and no inference should be drawn as to the relative merits of the systems for any other application.

TABLE 3.2-1. - STANDARD INDUSTRIAL CLASSIFICATION CODE TWO-DIGIT CLASSIFICATIONS WITHIN MANUFACTURING SECTOR OF U.S. INDUSTRY

SIC code	Industry group
20	Food and kindred products
21	Tobacco products
22	Textile mill products
23	Apparel and other finished products
24	Lumber and wood products, except furniture
25	Furniture and fixtures
26	Paper and allied products
27	Printing, publishing, and allied industries
28	Chemicals and allied products
29	Petroleum refining and related industries
30	Rubber and miscellaneous plastic products
31	Leather and leather products
32	Stone, clay, glass, and concrete products
33	Primary metal industries
34	Fabricated metal products
35	Machinery, except electrical
36	Electrical and electronic machinery, equipment, and supplies
37	Transportation equipment
38	Measuring, analyzing, and controlling instruments
39	Miscellaneous manufacturing industries

TABLE 3.2-2. - INDUSTRIAL PROCESSES SELECTED BY GE AND UTC FOR CTAS

SIC code	Industry group	GE	UTC	SIC code	Industry group	GE	UTC
2011	Meat packing	X	X	2824	Nylon fiber	X	X
2026	Fluid milk	X		2865	Styrene	X	X
2046	Wet corn milling	X		2865	Phenol-acetone	X	
2063	Beet sugar refining	X		2865	Ethylbenzene	X	
2082	Malt beverages	X	X	2865	Cumene	X	
2051	Baking		X	2869	Ethylene	X	X
2221	Broad-woven fabric		X	2869	Methanol	X	
2260	Textile finishing	X		2869	Isopropanol	X	
2421	Sawmill - softwood	X	X	2869	Ethanol	X	
2436	Plywood - softwood	X		2873	Ammonia	X	
2492	Particle board	X		2874	Phosphoric acid	X	
2621	Unbleached Kraft	X		2895	Carbon black	X	
2621	Newsprint plant	X	X	2911	Petroleum refining	X[a]	X
2621	Writing paper	X	X	3011	Tires and inner tubes	X	
2631	Corrugated paper	X	X	3211	Flat glass	X	
2631	Boxboard		X	3221	Glass containers	X	X
2631	Waste paper	X		3229	Pressed and blown glass	X	
2800	Integrated chemical		X[a]	3241	Portland cement	X	X
2812	Chlorine - caustic soda	X	X	3312	Integrated steel	X	X
2813	Cryogenic-O_2:N_2	X		3325	Ministeel	X	
2819	Alumina	X	X	3312	Steel specialty	X	
2821	High-density polyethylene		X	3321	Gray iron		X
2821	Low-density polyethylene	X	X	3331	Copper refining	X[a]	X
2821	Polyvinyl chloride		X	3334	Aluminum	X	
2822	Styrene-butadiene rubber	X	X	3711	Motor vehicles		X
2824	Polyester fiber	X					

[a]Studied in multiple sizes.

TABLE 3.2-3. - SIC SUBCLASSIFICATIONS EXAMINED IN CTAS

SIC code	Industry	GE	UTC
2011	Meat packing	X	X
2026	Fluid milk	X	
2046	Wet corn milling	X	
2051	Baking		X
2063	Beet sugar refining	X	
2082	Malt beverages	X	X

TABLE 3.2-4. - SIC 24 INDUSTRIES CONSIDERED IN CTAS

SIC code	Industry	GE	UTC
2421	Lumber sawmill	X	X
2436	Plywood veneer	X	
2492	Particle board	X	

TABLE 3.2-5. - SIC 26 INDUSTRIES CONSIDERED IN CTAS

SIC code	Industry[a]	GE	UTC
2621	(Unbleached Kraft pulping)	X	
2621	Newsprint (thermomechanical pulping)	X	X
2621	Writing paper (bleached Kraft pulping)	X	X
2631	Corrugated paper (neutral sulfite semichemical pulping)	X	X
2631	Boxboard		X
2631	Mill using waste paper as raw material	X	

[a]Pulping process identification used by GE is shown in parentheses.

TABLE 3.2-6. - SIC 28 INDUSTRIES CONSIDERED IN CTAS

SIC code	Industry	GE	UTC
2800	Integrated chemical	X	
2812	Chlorine - caustic soda	X	X
2813	Cryogenic-O_2:N_2	X	
2819	Aluminum	X	X
2821	High-density polyethylene		X
2821	Vinyl chloride	X	
2821	Low-density polyethylene	X	X
2821	Polyvinyl chloride		X
2822	Styrene-butadiene rubber	X	X
2824	Polyester fiber	X	
2824	Nylon fiber	X	X
2865	Styrene	X	X
2865	Phenol-acetone	X	
2865	Ethylbenzene	X	
2865	Cumene	X	
2869	Ethylene		X
2869	Methanol	X	
2869	Isopropanol	X	
2869	Ethanol	X	
2873	Ammonia	X	
2874	Phosphoric acid	X	
2895	Carbon black	X	

TABLE 3.2-7. - SIC 32 INDUSTRIES CONSIDERED IN CTAS

SIC code	Industry	GE	UTC
3211	Flat glass	X	
3221	Glass containers	X	X
3229	Pressed and blown glass	X	
3241	Portland cement	X	X

TABLE 3.2-8. - SIC 33 INDUSTRIES CONSIDERED IN CTAS

SIC code	Industry	GE	UTC
3312	Integrated steel	X	X
3312	Specialty steel	X	
3321	Gray iron		X
3325	Ministeel	X	
3331	Copper refining	X	X

TABLE 3.3-1. - CONVERSION SYSTEM AND FUEL COMBINATIONS

System	Fuel							
	Petroleum		Coal-derived liquids			Coal		
	Distillate	Residual	Distillate	Residual	Flue gas desulfurization	Atmospheric fluidized bed	Pressurized fluidized bed	Gasifier
Steam turbine	---------	[a]GE, [a]UTC	-------	GE, UTC	[a]GE, [a]UTC	GE, UTC	GE	--------
Open-cycle gas turbine:								
Simple	[a]GE, [a]UTC	[a]GE, UTC	-------	GE, UTC	---------	UTC	UTC	UTC
Recuperated	---------	---------	GE	-------	---------	-------	---	--------
Steam injection	---------	UTC	-------	GE, UTC	---------	UTC	UTC	--------
Combined gas turbine/ steam turbine	[a]UTC	UTC	-------	GE, UTC	---------	UTC	UTC	GE
Diesel:								
Low speed	---------	[a]UTC	-------	UTC	UTC	-------	---	--------
Medium speed	[a]GE	[a]GE	-------	GE	---------	-------	---	--------
High speed	[a]UTC	--------	UTC	-------	---------	-------	---	--------
Closed-cycle gas turbine	---------	--------	-------	UTC	---------	GE, UTC	---	--------
Stirling engine	---------	--------	GE	GE, UTC	GE	UTC	---	--------
Fuel cell:								
Phosphoric acid	UTC	--------	GE, UTC	-------	---------	-------	---	--------
Molten carbonate	UTC	--------	GE, UTC	-------	---------	-------	---	GE, UTC
Molten carbonate/ steam	---------	--------	-------	-------	---------	-------	---	GE
Thermionic	---------	--------	-------	GE, UTC	GE	-------	---	-------
Thermionic/steam	---------	--------	-------	GE, UTC	GE	-------	---	--------

[a]Case analyzed with current commerically available technology.

TABLE 3.3-2. - MAJOR PARAMETERS STUDIED FOR ADVANCED-TECHNOLOGY ENERGY CONVERSION SYSTEMS

System	Parameter	General Electric Co.	United Technologies Corp.
Steam turbine	Turbine configuration	Noncondensing with back pressure at process required pressure	Condensing with single extraction at 50 or 600 psig
	Throttle pressure/temperature, psig/°F	1450/1000, 850/825	1200/950, 1800/1050
	Boiler type	AFB, PFB	AFB
Open-cycle gas turbine:			
Liquid fueled	Turbine inlet temperature, °F	2200, 2600	2500
	Pressure ratio	8 to 16	10 to 18
	Recuperator effectiveness:		
	With residual fuel	0	0
	With distillate fuel	0, 0.6, 0.85	----------------
	Ratio of steam injection rate to airflow	0, 0.1, 0.15	0, 0.05, 0.1
	Bottoming cylce	None, steam	None, steam
Coal fired	Turbine inlet temperature, °F:		
	With gasifier	2200	2400, 2500
	With PFB	----------------	1600
	With AFB	----------------	1500
	Pressure ratio:		
	With gasifier	10	17, 18
	With PFB	----------------	6 to 10
	With AFB	----------------	10
	Gasifier type	Entrained bed	Entrained bed
	Bottoming cycle	Steam	None, steam
Diesel:			
Low speed (2 cycle)	Speed, rpm	----------------	120
	Jacket coolant temperature, °F	----------------	266
	Unit size, MW	----------------	8 to 29
Medium speed (4 cycle)	Speed, rpm	450	----------------
	Jacket coolant temperature, °F	250	----------------
	Unit size, MW	0.3 to 15	----------------
High speed (4 cycle)	Speed, rpm	----------------	1800
	Jacket coolant temperature, °F	----------------	Adiabatic
	Unit size, MW	----------------	0.2 to 15
Closed-cycle gas turbine	Working fluid	Helium	Air, helium
	Turbine inlet temperature, °F:		
	With AFB	1500	1500
	With liquid fuel	----------------	2200

TABLE 3.3-2. - Concluded.

System	Parameter	General Electric Co.	United Technologies Corp.
Closed-cycle turbine (concluded)	Pressure ratio:		
	With helium	2.5	3 to 6
	With air	------------------	3 to 11
	Recuperator effectiveness	0, 0.6, 0.85	0, 0.85
	Compressor inlet temperature, °F	80	100, 300
Stirling engine	Fluid	Helium	Helium
	Maximum fluid temperature, °F:		
	With coal - flue gas desulfurization	1300	-----------------
	With coal - AFB	------------------	1450
	With liquid fuel	------------------	1600
	Heat input configuration:		
	With coal	Intermediate heat-transfer gas loop	Intermediate heat-transfer gas loop
	With liquid fuel	Heater head in combustion zone	Intermediate heat-transfer gas loop
	Engine coolant temperature, °F	As required by process up to 500	150
	Unit size, MW	0.5 to 2	0.5 to 30
Fuel cell:			
Phosphoric acid	Stack temperature/pressure, °F/psia	375/15	400/120
	Fuel processing:		
	With petroleum-derived fuel	Steam reformer	Steam reformer
	With coal-derived fuel	Steam reformer	Adiabatic reformer
Molten carbonate	Cell stack temperature, °F	1000 to 1300	1100 to 1300
	Cell stack pressure, psia	147	120
	Cell stack temperature control configuration:		
	With distillate-grade fuel	Cathode recycle	Anode recycle
	With gasifier	Excess cathode air	Anode recycle
	Gasifier type (coal-fired case)	Entrained bed	Entrained bed
	Bottoming cycle	None, steam with gasifier	None
Thermionics	Emitter collector temperature, °F	2420/710, 1880/900	2400/763, 2400/1113
	Configuration	Modular array	Thermionic heat exchanger (THX)
	Air preheat temperature, °F	1000	2200, 1000
	Bottoming cycle	None, steam	None, steam

TABLE 3.3-3. - MAJOR PARAMETERS STUDIED FOR STATE-OF-THE-ART ENERGY CONVERSION SYSTEMS

System	Parameter	General Electric Co.	United Technologies Corp.
Steam turbine	Configuration	Noncondensing with back pressure at process required pressure	Condensing with single extraction at 50 or 600 psig
	Throttle pressure/temperature, psig/°F	1450/1000 850/825	1200/950 -----------------
	Fuel	Pulverized coal with flue gas desulfurization, petroleum residual	Pulverized coal with flue gas desulfurization, petroleum residual
Gas turbine: Petroleum distillate fueled	Turbine inlet temperature, °F Pressure ratio	2000 10	2000 10 to 14
Petroleum residual fueled	Turbine inlet temperature, °F Pressure ratio	1750 10	----------------- -----------------
Diesel: Petroleum distillate fueled	Type	Medium speed, 4 cycle	High speed, 4 cycle
	Speed, rpm Jacket coolant temperature, °F Unit size, MW	450 180 0.3	1800 200 0.4 to 1.5
Petroleum residual fueled	Type	Medium speed, 4 cycle	Low speed, 2 cycle
	Speed, rpm Jacket coolant temperature, °F Unit size, MW	450 155 1 to 10	120 158 8 to 29

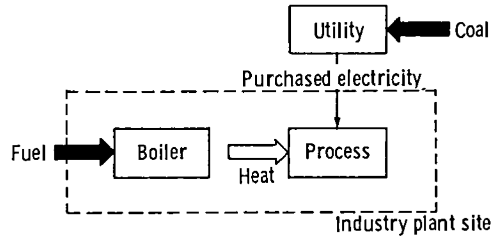
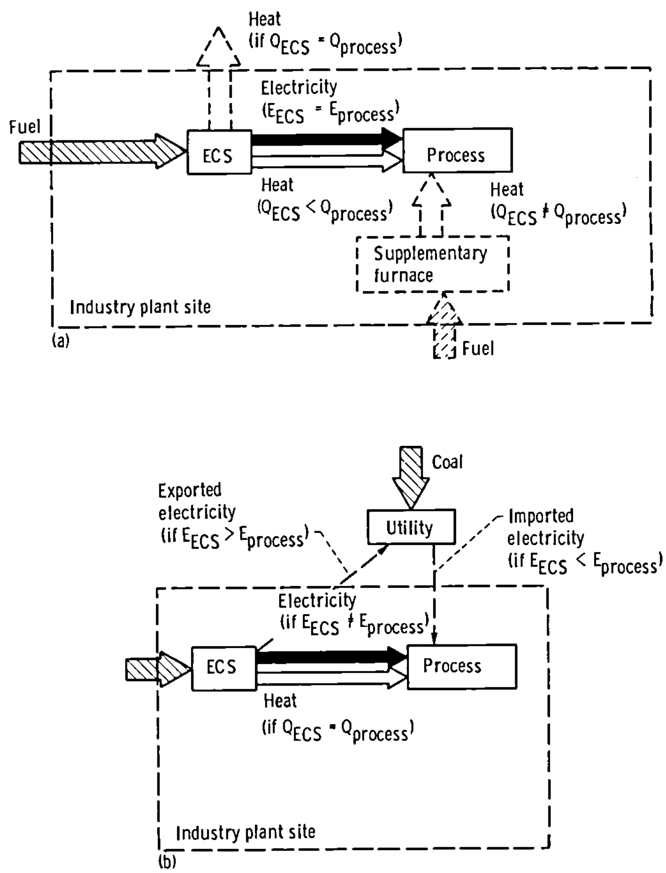


Figure 3.1-1. - CTAS noncogeneration case.



(a) Match-electricity strategy.
(b) Match-heat strategy.

Figure 3.1-2. - CTAS cogeneration matching strategies for topping configurations.

SIC code	Industry group	Energy consumption in 1975, percentage of industrial energy consumption	Number of SIC four-digit classifications in group
28	Chemicals and allied products	22.7	28
33	Primary metal industries	19.8	14
29	Petroleum refining and related industries	9.5	5
26	Paper and allied products	9.2	17
32	Stone, clay, glass, and concrete products	8.4	27
20	Food and kindred products	7.3	47
37	Transportation equipment	3.3	17
22	Textile mill products	3.1	30
30	Rubber and miscellaneous plastic products	2.2	6
24	Lumber and wood products	2.1	17

Figure 3.2-1. - Top 10 energy-consuming industries in U.S. manufacturing sector.

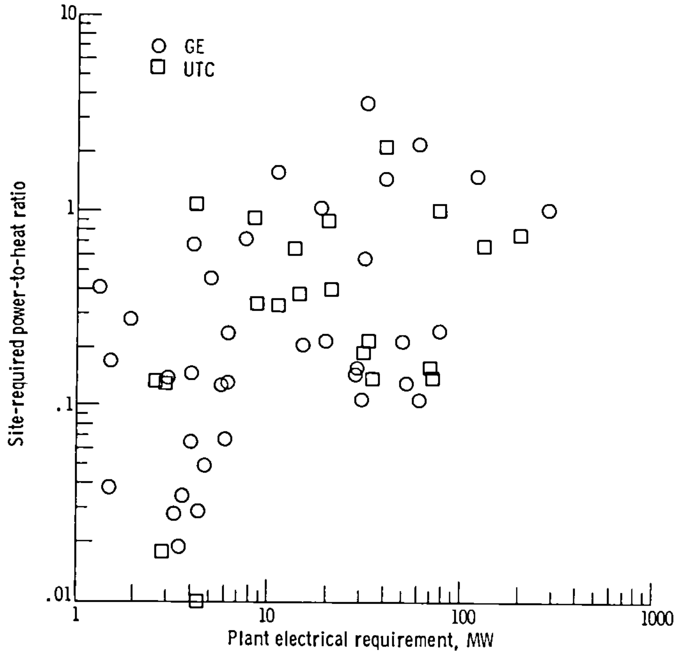


Figure 3. 2-2. - Size distribution of CTAS processes.

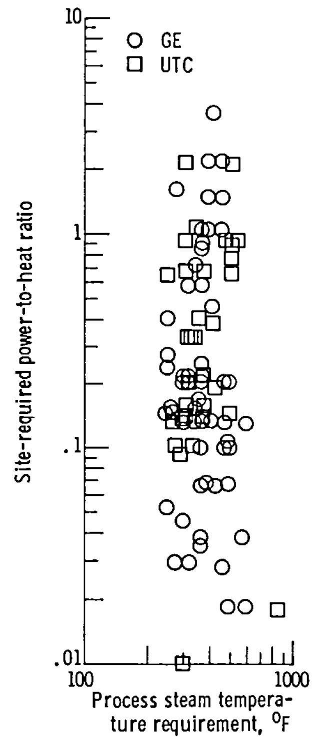


Figure 3. 2-3. - Process steam temperature requirements of CTAS processes.

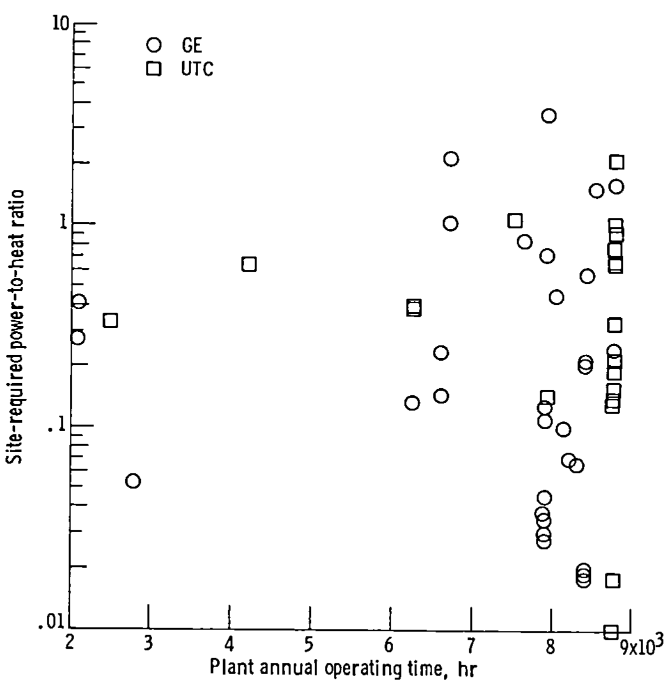


Figure 3. 2-4. - Load factors of CTAS processes.

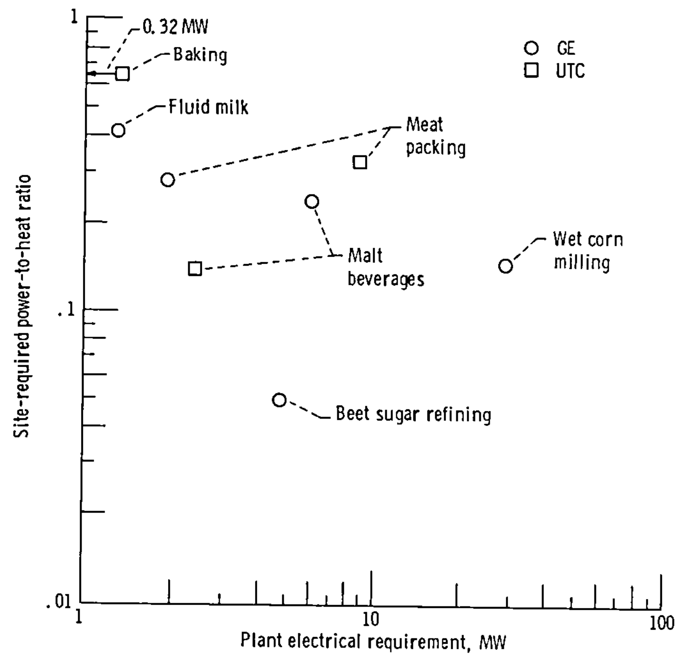


Figure 3. 2-5. - Size distribution of selected plants from standard industrial classification code 20 - food and kindred products.

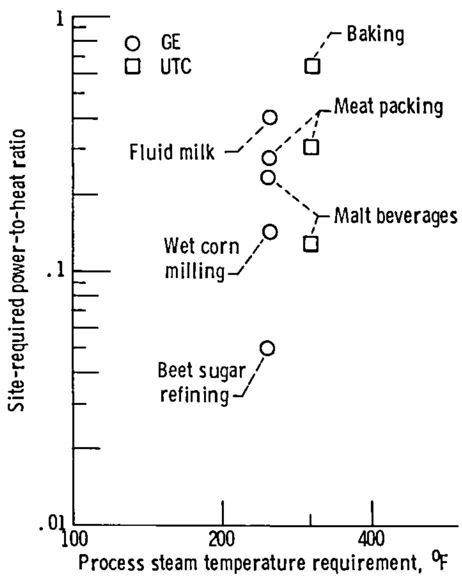


Figure 3.2-6. - Process steam temperature requirements of selected plants from standard industrial classification code 20 - food and kindred products.

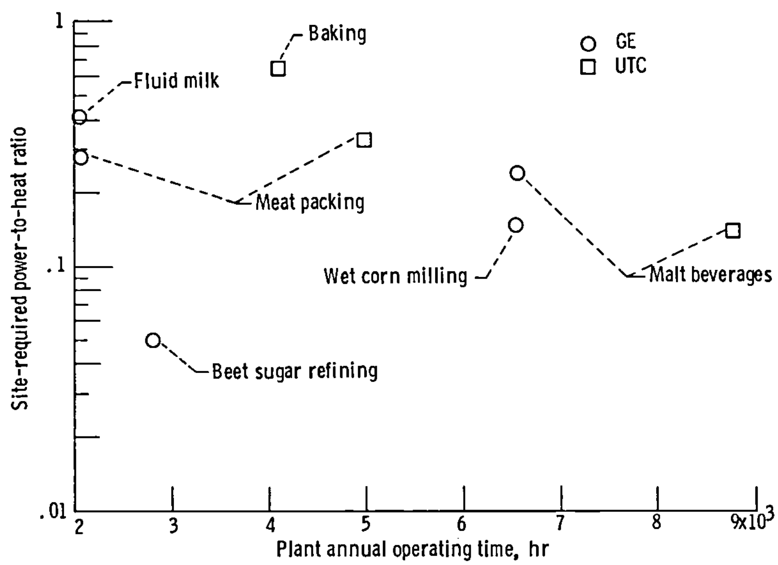


Figure 3.2-7. - Load factors of selected plants from standard industrial classification code 20 - food and kindred products.

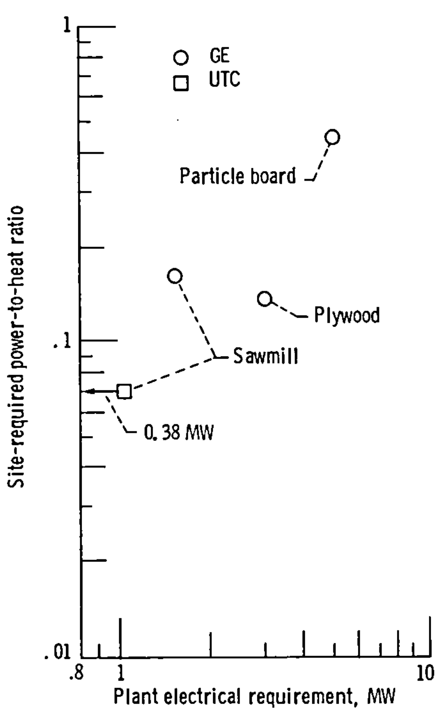


Figure 3.2-8. - Size distribution of selected plants from standard industrial classification code 24 - lumber and wood products, except furniture.

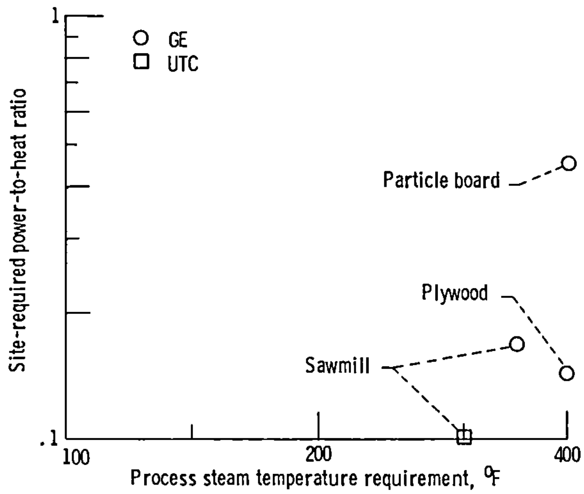


Figure 3. 2-9. - Process steam temperature requirements of selected plants from standard industrial classification code 24 - lumber and wood products, except furniture.

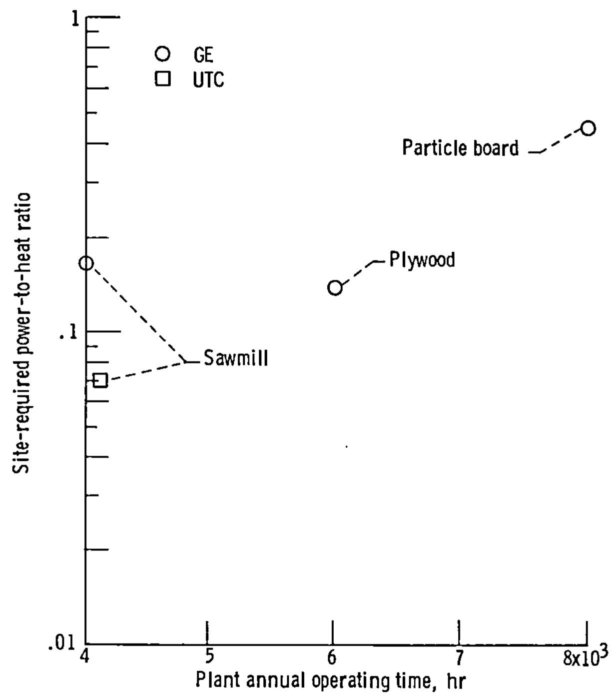


Figure 3. 2-10. - Load factors of selected plants from standard industrial classification code 24 - lumber and wood products, except furniture.

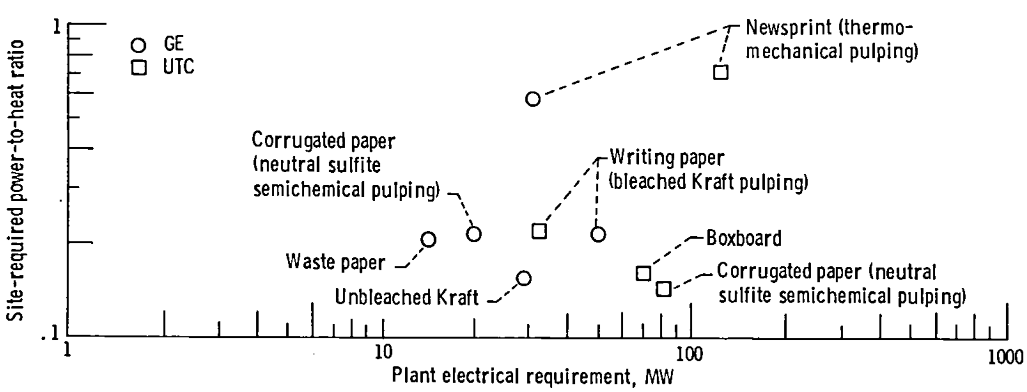


Figure 3. 2-11. - Size distribution of selected plants from standard industrial classification 26 - paper and allied products.

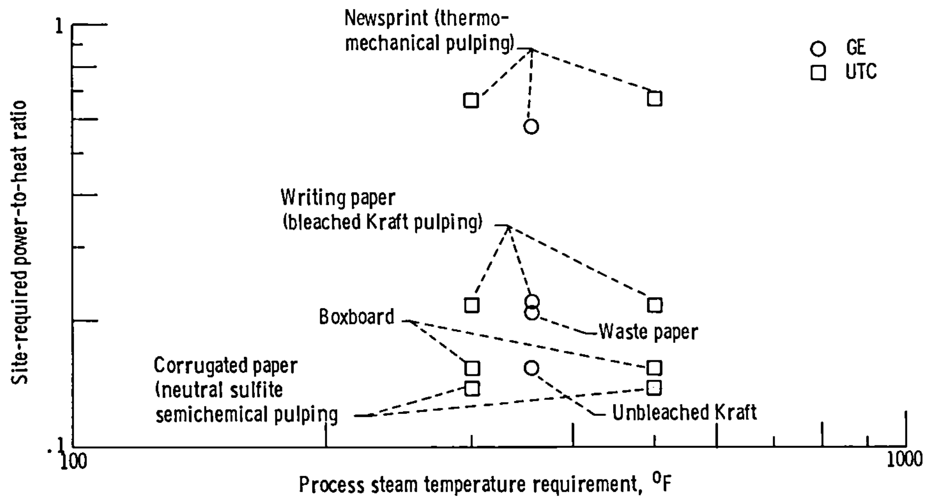


Figure 3.2-12. - Process steam temperature requirement of selected plants from standard industrial classification code 26 - paper and allied products.

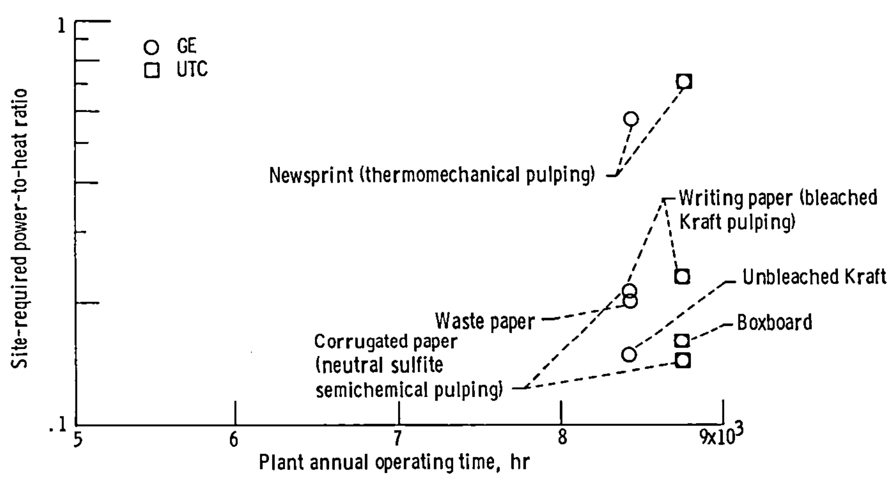


Figure 3.2-13. - Load factors of selected plants from standard industrial classification code 26 - paper and allied products.

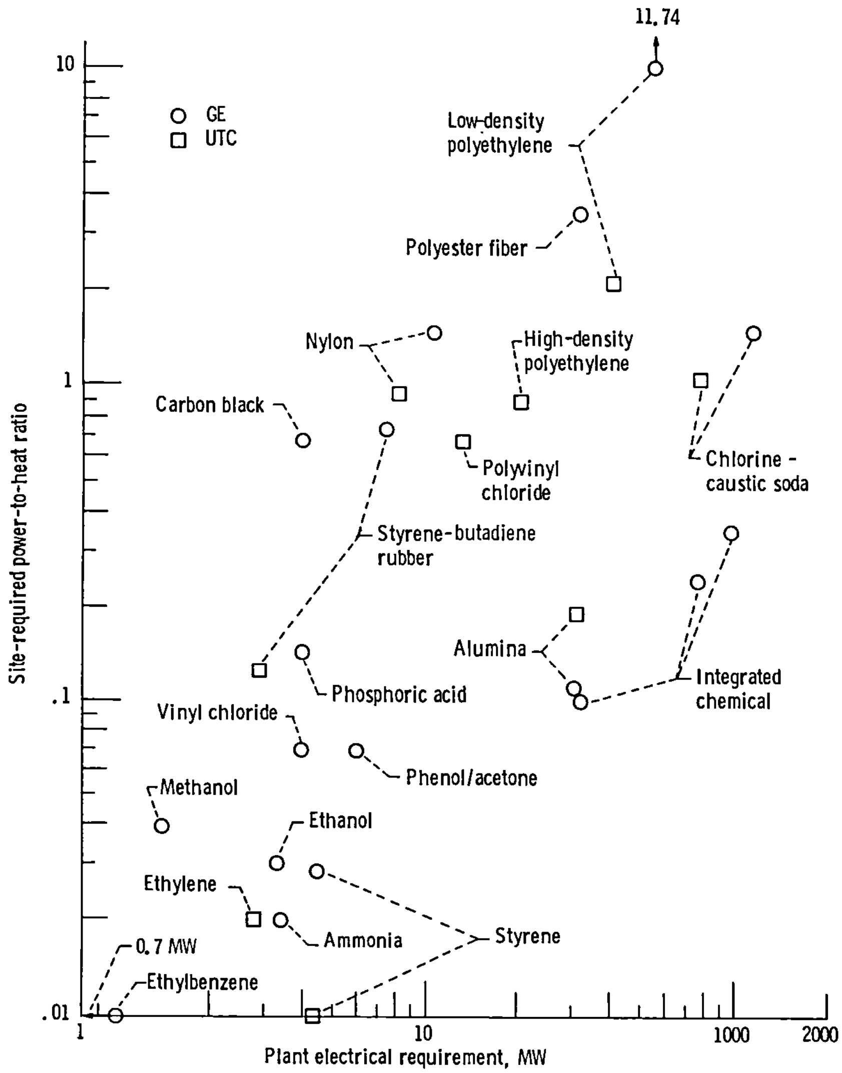


Figure 3.2-14. - Size distribution of selected plants from standard industrial classification code 28 - chemicals and allied products.

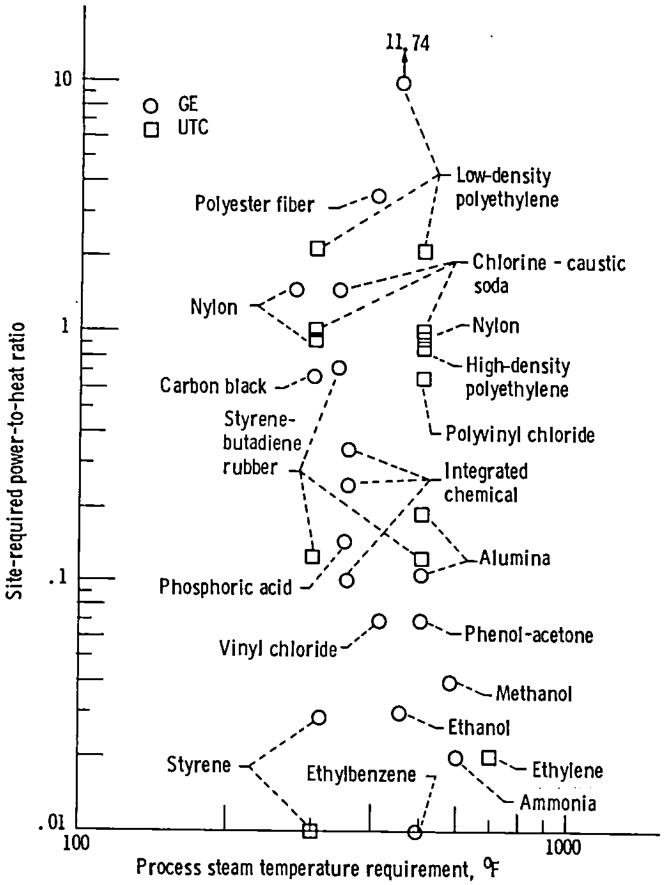


Figure 3.2-15. - Process steam temperature requirements of selected plants from standard industrial classification code 28 - chemicals and allied products.

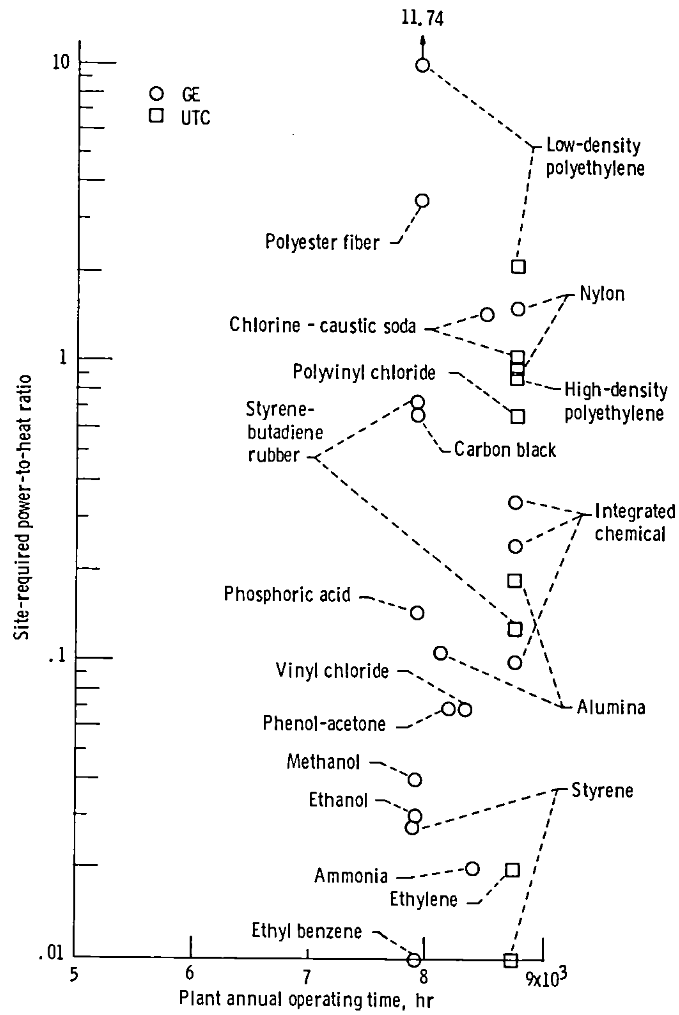


Figure 3.2-16. - Load factors of selected plants from standard industrial classification code 28 - chemicals and allied products.

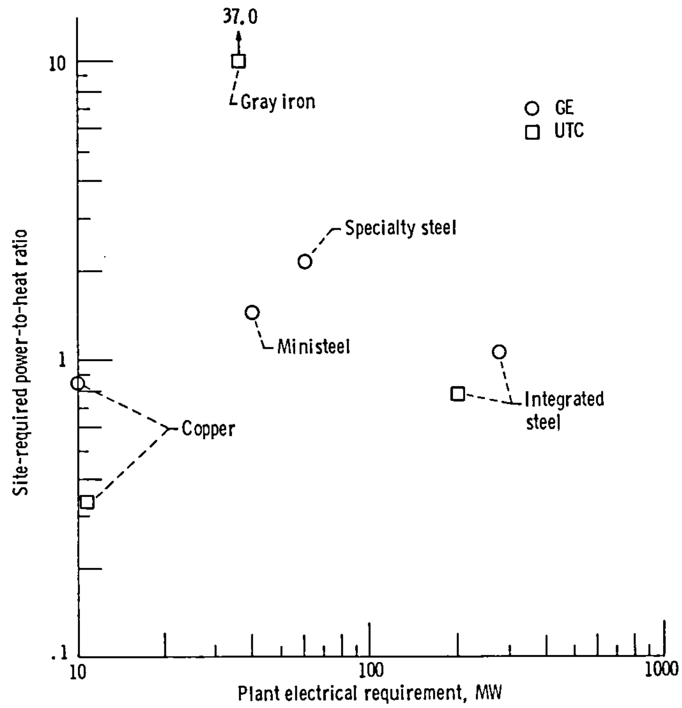


Figure 3.2-17. - Size distribution of selected plants from standard industrial classification code 33 - primary metal industries.

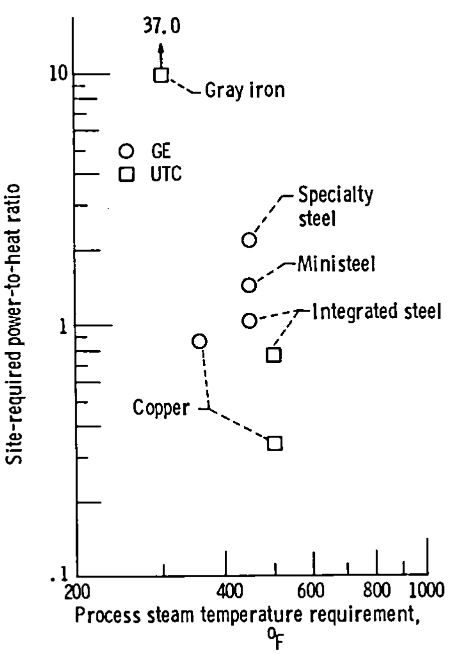


Figure 3.2-18. - Process steam temperature requirements of selected plants from standard industrial classification code 33 - primary metal industries.

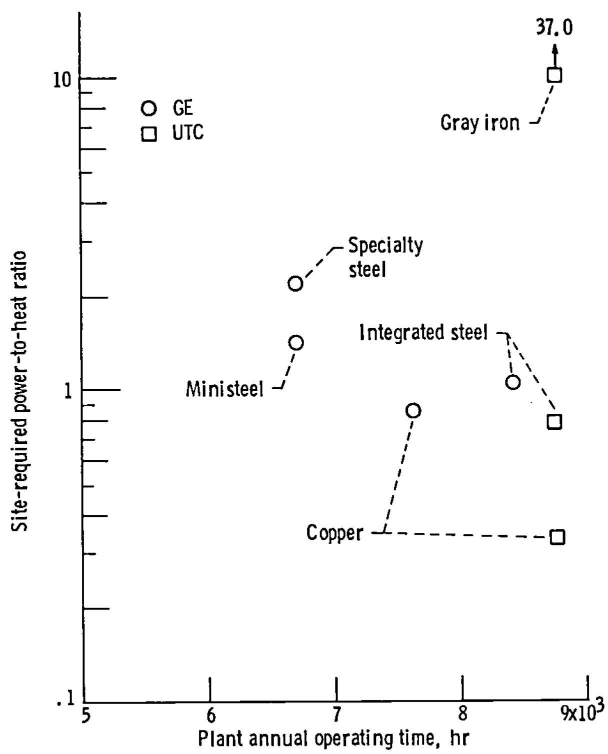


Figure 3.2-19. - Load factors of selected plants from standard industrial classification code 33 - primary metal industries.

4.0 STUDY METHODOLOGY

Gary D. Sagerman

This section discusses the major assumptions used in the study and the screening process used by Lewis in evaluating results for the various advanced energy conversion systems. Section 4.1 describes the common ground rules established by Lewis for use in the study. Section 4.2 describes the major assumptions made by the contractors, which are specific to each contracted study. Section 4.3 defines some of the output parameters specified by Lewis for common use in the study. Section 4.4 describes the process used by Lewis in its evaluation of study results.

4.1 COMMON GROUND RULES

A set of ground rules was established by NASA in cooperation with DOE and the contractors in order to ensure that the contractors' results could be compared on a consistent basis and that differences that occurred would not be attributable to arbitrary differences in the basic study assumptions. The major areas where common ground rules were established are

(1) Fuel characteristics
(2) Utility characteristics
(3) Fuel and electricity prices
(4) Emissions guidelines
(5) Capital costing approach and economic methodology
(6) Output parameters

A number of the most significant ground rules are discussed in the following paragraphs.

4.1.1 Fuel Characteristics and Price

Figure 4.1-1 shows the fuels considered for use in CTAS. The emphasis, as indicated in the figure, was on the use of high-sulfur coal, minimally processed coal-derived liquid fuels, and low- or intermediate-Btu gas obtained through onsite gasification of coal. Residual-grade petroleum oil was considered as an intermediate step from the clean fuels in use in most currently available systems toward the use of coal-derived fuels. A small number of systems (primarily state-of-the-art configurations) that use distillate fuel were also examined. The fuel specifications provided to the contractors are summarized in table 4.1-1. The specifications shown for the petroleum distillate fuel and the petroleum residual fuel represent characteristics near the upper limits of current specifications for number 2 diesel oil and number 5 boiler-grade fuel, respectively, and are not necessarily typical of the fuels being used today. The coal-derived liquid fuels specified are not the outputs of any particular liquefaction process but represent what might be future characteristics of minimally processed coal-derived liquid fuels in grades similar to the specified petroleum fuels. Characteristics of the low- or intermediate-Btu gas were not specified by Lewis but depend on the specific gasifier concepts selected by the respective contractor.

Prices assumed for the fuels are given in table 4.1-2. Prices for the petroleum-based fuels and coal were based on projections for industrial uses made by the DOE Energy Information Administration. These data were provided to Lewis by DOE for use in CTAS. Prices for coal-derived liquid fuels were assumed to be the same as the prices for petroleum-based fuels of comparable grades, on the assumption that for coal-derived liquid fuels to achieve a significant degree of usage in industry the effective price to the user would have to be competitive with that of petroleum fuels. The prices shown are projected national averages. The impact of regional differences in fuel prices (and electricity prices) was examined by Lewis.

In some industrial processes included in the study byproduct fuels are available. The characteristics of byproduct fuels and the amounts of byproduct fuels available were determined by the contractors from their data for the industrial processes. When byproduct fuels are used, they are assumed to be available at no charge.

4.1.2 Utility Characteristics and Electricity Price

Electricity purchased from a utility was assumed to be baseload power generated by a coal-fired steam powerplant at an efficiency of 32 percent including transmission and distribution losses. The utility was assumed to exactly meet the emissions guidelines for coal-fired systems as described herein. The prices assumed for electricity (in 1978 dollars) are

(1) Purchase price for utility electricity in 1985 is 3.3¢/kW-hr (based on DOE input)
(2) Electricity purchase price escalation, 1 percent above inflation (based on DOE input)
(3) Price received by cogenerator for electricity exported to the grid (sell-back price), 60 percent of purchase price

The purchase price and the escalation rate were based on the same DOE Energy Information Administration data as the fuel prices. Electricity prices were based on projected prices for industrial customers. Average demand charges were assumed to be included in the price of electricity. Standby charges for electricity were not considered. Although standby charges can be significant in any given application being considered for implementation, they are highly variable. For this broad screening study of advanced energy conversion systems the effect of these charges was not addressed. As in the case of the fuel prices the electricity prices were national average values. Furthermore a flat electricity rate was assumed, that is, no variation in price with size of electrical demand.

The sale price of exported electricity was established by Lewis, with DOE approval, after discussion with several utilities and the CTAS contractors. The 60 percent value is roughly equivalent to the cost of fuel required by a utility to generate a like amount of electricity.

4.1.3 Emissions Guidelines

A set of emissions guidelines was established to provide the contractors with a common level that should not be exceeded in formulating their cogeneration system designs. These guidelines were based on the 1971 Federal New

Source Performance Standards (NSPS) for steam powerplants, which were in effect at the start of this study, and on NSPS that were proposed in 1977 for stationary gas turbines. The guidelines, presented in table 4.1-3, are fuel dependent and are based on the fuel energy input to the powerplant. Note that the guidelines for solid coal were also applied to cases where onsite gasification is used. The emissions guidelines were reviewed by both DOE and the Environmental Protection Agency (EPA), prior to their use in CTAS, for appropriateness in a study such as this, which is aimed at comparing a wide variety of advanced energy conversion systems. Conversion systems that did not meet the guidelines were not eliminated from further study but were flagged for their failure to meet the guidelines. It is important to note that some states have more stringent standards for steam powerplants than those delineated in the 1971 NSPS. State-by-state emissions standards and data on nonattainment areas were cataloged by JPL in support of CTAS and have been included in the detailed NASA report (appendix A).

4.1.4 Capital Costing Approach

All capital costs are given in 1978 dollars, and interest during construction was included when the capital costs were used in the economic analyses. Capital costs were estimated for all onsite equipment associated with the generation of electricity and process heat. Capital costs for distribution of power or heat, condensate return systems, and process-related equipment were not included in the cost estimates since the same equipment would be used with or without cogeneration.

An "island" approach to capital costing was specified by Lewis for use by both CTAS contractors. Each total cogeneration system was made up of a number of major subsystems (e.g., fuel handling, furnace, and conversion systems). Each major subsystem and the balance-of-plant equipment associated directly with that subsystem make up a cost "island." The major cost islands used by the two CTAS contractors are shown in table 4.1-4. Costs were estimated by the contractors for the equipment, installation, material, and labor for each island from inputs generated by the conversion system consultants on their CTAS team or from cost models based on experience with existing similar equipment or previous studies. All equipment, material, and labor that were required to tie together the separate subsystem islands into a total cogeneration system and that could not be conveniently allocated to a specific subsystem island were accounted for in a balance-of-plant (BOP) island.

The contractors' cost categories were reviewed and coordinated by Lewis early in the study in order to achieve, where practical, consistency between the contractors in the level of breakdowns and in the equipment included in the various islands. The contractors reported costs at one level of detail greater than that shown in table 4.1-4. Because of the diversity of data sources and the methodologies used by the two contractors in developing cost estimates, it was not always possible to establish directly comparable cost islands. For example, in the UTC cost breakdown, costs for the heat source and associated cleanup equipment for the energy conversion system were in their item 2. Costs for a supplementary furnace and associated equipment, when required, were reported under their item 5. In the GE cost breakdown, costs for the energy conversion system heat source and the supplementary

furnace, when required, were both reported under GE's item 2. Sufficiently detailed cost data were reported to allow Lewis to compare costs and to evaluate differences where they occurred.

The total installed costs for the appropriate subsystem islands were summed together with costs for the balance-of-plant island. Cost adders such as indirect labor costs, contingency, engineering services, and fees were then included to obtain the total cogeneration system capital costs. Each contractor used cost adders that were consistent with his data sources and costing methodology. The cost adders used are given in table 4.1-5.

4.1.5 Economic Assumptions

A wide variation is possible in the methodology and assumptions used in the economic analyses of a proposed venture. To facilitate the comparison of results generated by the two contractors, Lewis, after consultation wih the contractors and DOE, specified a set of ground rules to be followed in the CTAS economic analyses. Two primary parameters that were used in CTAS as measures of economic attractiveness were levelized annual energy cost and return on investment. They are defined in section 4.3 and discussed in appendixes B and C.

Several of the more important assumptions used in the economic analyses are listed in table 4.1-6. The values were specified by Lewis after consultation with the contractors, and the assumptions were provided to DOE for review before being incorporated into the study.

4.2 CONTRACTOR-SPECIFIC ASSUMPTIONS

There were a number of important areas where NASA elected not to establish common ground rules but to allow the contractors to incorporate their individual philosophies, design approaches, and methodologies. A few of these areas where the contractor-specific assumptions have a significant effect on the study results are discussed briefly here.

4.2.1 Noncogeneration Case

The noncogeneration case was the baseline against which all cogeneration system energy costs and emissions savings were measured. Thus the assumptions that were made in defining the noncogeneration case could, in some cases, have a significant effect on the absolute value of the results. The noncogeneration cases established by both contractors differed only in their philosophies on the fuel that was assumed for the onsite furnaces producing process heat. UTC assumed that noncogeneration plants built from 1985 to 2000 would predominantly use liquid fuels in their process heat furnaces, similar to current practice. They assumed that whatever liquid fuel was available for the cogeneration system could also be available for use with the noncogeneration system. Therefore, when UTC examined cogeneration systems based on commercially available or advanced systems that use petroelum-based fuels, they assumed the noncogeneration fuel to be residual-grade petroleum oil. When UTC considered advanced cogeneration systems fueled by coal or coal-derived liquids, they assumed the noncogeneration fuel to be a residual-grade, coal-

derived liquid. The GE approach was to assume that for noncogeneration plants built from 1985 to 2000, coal would be the predominant fuel for the onsite furnaces when the plant size was sufficient to support the equipment required (process heat required, $>30 \times 10^6$ Btu/hr). In smaller plants GE assumed the noncogeneration fuel to be coal-derived residual oil.

This difference in noncogeneration fuel had a significant effect on the absolute values of the results, especially energy cost saving and return on investment for the cogeneration systems. This effect is discussed in appendix B. To obtain data that permitted a more direct comparison between the contractors' results, GE was requested to provide computer data for all of their cases for a noncogeneration fuel consistent with that assumed by UTC, in addition to data based on their assumption. The liquid-fueled noncogeneration case, for which data are available from both contractors, is used throughout this report for comparing results.

4.2.2 Process Heat Requirements

The two CTAS contractors chose different methods of defining and matching the process requirements and conversion system capabilities in the area of process heat. The significant differences are discussed briefly in this section.

UTC elected to specify five "bins" into which all process heat requirements were categorized in order to enable them to proceed with their system designs independently of the industrial process data. The bins were specified as 140° F hot water, 300° F (50 psig) saturated steam, 500° F (600 psig) saturated steam, 700° F (600 psig) superheated steam, and direct heat. In some cases direct-heat requirements could be satisfied through the direct use of the gaseous exhaust from an energy conversion system. The energy conversion system design options were configured to provide recoverable heat for one or more of these bins. UTC and Gordian Associates examined the process requirements and, using their judgment, placed them in the appropriate bins. This technique for matching the system capability with the process requirements enabled UTC to then satisfy multiple-temperature process heat requirements. In general a process heat requirement was placed in the next higher temperature bin (e.g., a 375° F requirement would be placed in the 500° F bin). When the energy conversion system capability was determined, it was typically adjusted to the next lower temperature bin (e.g., if the maximum temperature a system could provide was 400° F, it was adjusted to the 300° F bin). This methodology allowed consideration of multiple-temperature process requirements. In some cases (especially where only relatively low-grade heat was available from the system) it yielded conservative results.

GE developed a characteristic for each conversion system that expressed the electric output and the amount of recoverable waste heat available from that system as a function of the temperature at which the process heat was required. This characteristic assumed that for a given plant all process heat was provided at one temperature. When GE identified an industrial process with multiple-temperature process heat requirements, they combined the multiple heat streams into a single representative requirement roughly equal to the total heat energy requirement of the multiple streams and generally at the

highest temperature required by the process. They then matched the performance characteristic of the energy conversion system with the single representative requirement. This methodology tends to yield conservative results for those processes requiring multiple process heat streams at different temperatures, since all of the process heat energy is generated at the highest temperature required. The approach of generating steam at one temperature when the process needs steam at more than one temperature is often used in industry today.

The effects of the GE and UTC assumptions on the results have been examined by Lewis. In general the methodology used by each contractor yielded results of sufficient accuracy for the screening purposes of CTAS. In some instances Lewis or the contractors recalculated the results where the assumptions may have inadvertently penalized one or more systems.

4.2.3 Energy Conversion System Unit Sizing

The philosophies of the two contractors differed somewhat in their sizing of energy conversion system units to meet the total power requirements determined by the cogeneration matching strategy. GE established a maximum unit size limit for each system. If the total power requirement could be satisfied by a unit smaller than the maximum size, a single unit was used. If the total power requirement was greater than the maximum unit size for the system being considered, the minimum number of equal-sized units of that type was used to satisfy the requirement. At the small end, if the size of the unit required was smaller than the lower end of the range covered by the GE cost model, the model was extrapolated and the results flagged as being outside the range of available data and probably optimistic. In selecting cases for detailed economic study the flagged cases were not considered.

The primary difference between the GE and UTC approaches in this area was UTC's belief that, in order to increase the flexibility of the cogeneration systems and to insure a capability to shut down the industrial process without damage to process equipment, multiple units of energy conversion systems should always be used. Therefore all of the UTC cogeneration systems used at least two equal-sized units until the maximum unit size was reached. Then the minimum number of equal-sized units was used to meet the requirements. UTC also flagged those cases that were smaller than the minimum practical size, and they were not considered in selecting cases for detailed economic study.

Equipment to provide additional electrical or thermal capacity for standby purposes to be used in the event of failure of the primary equipment so that full production capability could be maintained was not included as part of the cogeneration systems. Examination of the consequences or economics of forced outages versus having standby electrical or thermal capacity was beyond the scope of this broad screening study. Of course it can be an important consideration in the design of a cogeneration system for a specific application and can have a significant influence on the final economic attractiveness of a proposed venture.

4.3 DEFINITION OF EVALUATION PARAMETERS

A large variety of parameters can be used to characterize cogeneration system performance and economics. Lewis specified a basic set of output parameters to be used by both contractors not only so that numerical results would be directly comparable, but also because Lewis felt that these parameters were particularly suitable for use in a study such as this one.

Each contractor was also permitted to use other output parameters in addition to the ones specified. Four parameters specified by Lewis and used extensively in this report are fuel energy saving ratio (FESR), emissions saving ratio (EMSR), levelized annual energy cost saving ratio (LAECSR), and rate of return on investment (ROI). These are defined in section 2.5 and discussed in the following paragraphs. The factors affecting results for these and other evaluation parameters are discussed in appendix B.

4.3.1 Fuel Energy Saving Ratio

The fuel energy saving ratio (FESR) parameter specified to measure cogeneration system performance is the saving of fuel energy as compared with that required to meet the site requirements without cogeneration.

The fuel energy in the cogeneration case includes that used by the cogenerating energy conversion system plus that required at the utility if additional electricity is required as well as that required by an onsite furnace or boiler if additional process heat is required. In the noncogeneration case the fuel energy is the sum of that used at the utility site to produce electricity and that used at the industrial site to produce heat. To be consistent, when the cogeneration case involves electricity exported back to the utility, the fuel energy at the utility in the noncogeneration case is adjusted to account for electricity production equal to that in the cogeneration case.

4.3.2 Emissions Savings Ratio

Because of the fuel saving there is usually a reduction in overall emissions, considering both the utility and industrial sites. The parameter used to measure this is analogous to the fuel energy saving ratio, that is, an emissions saving ratio (EMSR).

The emissions include those at the utility site and those at the industrial site. The emissions saving ratio was calculated individually for sulfur dioxide, oxides of nitrogen, and particulates, as well as for the sum of all three. In this summary report only values for the sum of all three emissions are presented. In addition to emissions where the plant site and utility were included together, each contractor cataloged the plant-site emissions by species for both the noncogeneration and cogeneration cases since onsite emissions can be a crucial factor for implementation of a cogeneration system.

4.3.3 Levelized Annual Energy Cost Saving Ratio

Levelized annual energy cost (LAEC) is defined as the minimum constant net revenue required each year of the life of the project to meet the expenses for energy (electricity and process heat) for the industrial plant including fuel, electricity and operating costs, the cost of money, and the recovery of the initial investment. A levelized annual energy cost saving ratio (LAECSR) was used in the study.

Items considered in the annual energy cost include fixed capital charges (including cost of debt and return on equity), fuel costs, operating and maintenance costs, costs for purchased electricity (if required), and credits for the sale of electricity (if excess is generated by the system). This is an investment analysis approach commonly used by electric utilities; however, the methodology is also applicable to industrial firms.

4.3.4 Return on Investment

Return on investment (ROI) is defined as the rate that equates the present value of all future cash flows with the initial capital investment. The ROI's calculated were based on the incremental investment required for a cogeneration system relative to the noncogeneration case. Cash flows were also incremental values relative to noncogeneration. The ROI's were calculated on an inflation-free, after-tax basis and as such represent a conservative estimate of the economic attractiveness of the cogeneration systems. ROI is frequently used by industry as one of the prime measures of the economic merit of a proposed venture.

4.4 LEWIS EVALUATION APPROACH

4.4.1 Plant-Basis Evaluation

The Lewis project team felt that all of the output parameters used in CTAS should be considered in identifying the most attractive advanced energy conversion systems. Furthermore it was decided to avoid the use of fixed, explicit weighting factors for the various parameters although would this allow a mathematical selection of the best alternative. Such a set of weighting factors would depend on site- and industry-specific considerations; on societal, political, and judgmental considerations that are difficult to quantify; and on considerations of system design or optimization that were beyond the scope and purpose of CTAS. Instead, a detailed screening method that was less formal mathematically but did consider all of the output parameters was used to select a relatively small group of the most attractive conversion systems from the CTAS results.

For the plant-basis results the detailed screening method used by NASA consisted of examining all of the cogeneration results in terms of one output parameter at a time to identify a group of energy conversion systems that yielded the higher values of that parameter. This detailed screening was done for nine representative industries included by both contractors in their studies. The industrial processes used for this purpose are identified in figure 4.4-1. The axes of figure 4.4-1 are identical to those of figure 3.2-2. The solid lines in figure 4.4-1 represent an envelope around the total set of

processes selected by the contractors and plotted in figure 3.2-2. Each set of two symbols connected by a dashed line represents the characteristic of the same SIC four-digit industrial plant as used by the two contractors. Although in the cases plotted in figure 4.4-1 the contractors studied the same generic process, each had projected data on a different specific plant. It is not unusual that variations in characteristics of the magnitude shown occur between two plants selected from the same four-digit industry group. Figure 4.4-1 shows that the nine industries selected as a subset provided a good representation of the total envelope of size and power-to-heat-ratio characteristics of the processes considered by the two contractors. Specific details on the size, power-to-heat-ratio, and temperature of the process heat required are shown in table 4.4-1 for the nine representative process plants.

The parameters included in the detailed plant-basis screening were fuel energy saving ratio, emissions saving ratio, return on investment, and levelized annual energy cost saving ratio. From the original set of energy conversion systems a smaller group was arrived at by considering which systems did well in terms of all of the parameters. The attractive cases identified in terms of each parameter were not restricted to a fixed number of cases nor restricted to include cases only with values above some predetermined cutoff value. The size of the list of attractive systems and the cutoff values were determined after considering such things as the number of attractive cases, the spread in the data, and the comparison of the advanced conversion systems with the state-of-the-art conversion systems.

The specific approach used in Lewis' detailed plant-basis screening is illustrated in figure 4.4-2. The data shown in this example consist of results generated by UTC for the newsprint process. The screening method consisted of a sequential consideration of each evaluation parameter as indicated in the various parts of the figure. Each part consists of a plot of the incremental capital investment required for cogeneration versus some return obtained. The return is in the form of operating cost saving, fuel energy saving, levelized annual energy cost saving, or emissions saving.

In the first step, figure 4.4-2(a), the incremental capital cost and the annual operating cost saving are considered. In this case, both of these parameters are referenced to the noncogeneration situation in which an onsite boiler burning coal-derived residual fuel is used to provide the required process steam and electricity is purchased to meet power requirements. A line from the origin to some cogeneration case is roughly a line of constant ROI (appendix B). The shallower the slope of a line from the origin to a cogeneration case, the higher the ROI for that case. As shown in figure 4.4-2(a), four advanced cogeneration cases achieved an ROI about equal to or greater than the highest ROI achieved by a state-of-the-art cogeneration case. (Actually a variation of the advanced gas turbine case, involving steam injection, had results very similar to those for the gas turbine case shown and was omitted from the figure for simplicity.) Many other cases also had good ROI, but the values were lower than the 20 percent for the state-of-the-art gas turbine and were not included in this figure. For this industrial process, in this step in the screening, a cutoff of 20 percent was used. However, as shown in other parts of the figure, some cases with lower ROI were eventually included. In other industrial processes, other cutoff values were used that were not necessarily associated with the results of a state-of-the-art case. Also, it is important to note that no restrictions were placed on cogeneration strategy or on whether electricity would be exported to the utility.

In the second step of the screening, shown in figure 4.4-2(b), incremental capital cost versus fuel energy saving ratio was considered. The five cases identified in the previous step as having the highest ROI are shown. Four additional cases, together with the advanced combined cycle burning coal-derived residual fuel, are the top five in terms of fuel energy saving ratio. Note that all of the advanced systems shown, except the steam turbine/AFB system, have fuel energy savings greater than that for the state-of-the-art gas turbine. The fuel energy saving for the steam turbine/AFB system was low because the power-to-heat ratio of this system did not match the ratio required for the newsprint industry. This particular cogeneration system was configured to produce the amount of process steam needed but produced only 13 percent of the required power. Therefore only limited benefits of cogeneration were realized.

It is emphasized that figure 4.4-2(b) contains only the five cases with highest ROI and the five cases with highest fuel energy saving ratio (a total of nine distinct cases). The cutoff shown in the figure applies only to these cases; it does not imply that all cases with higher than 22 percent fuel saving are included. For example, a Stirling engine using coal-derived residual fuel achieved a fuel energy saving in this industry of 28 percent with an ROI of 6 percent. It was not shown in this figure since it is not among the most attractive cases in terms of either parameter.

The next part of step 2, shown on the right side of figure 4.4-2(b), is to reconsider the incremental capital cost versus the annual operating cost saving. The gas turbine/PFB case has an ROI just below the previous 20 percent cutoff, and the molten carbonate/gasifier fuel cell has an ROI of 13 percent. Since both these cases have high fuel energy savings, they were provisionally retained at this point. The other two cases that were identified as having high fuel energy savings have much lower annual operating cost savings (because of the higher price of their distillate-grade fuel). Therefore they have much lower ROI and were dropped from further consideration at this point. Again it should be clear that the cutoff shown in this figure (i.e., ROI $\geq$ 13 percent) does not mean that all cases with higher than 13 percent ROI are included.

The third step of the screening, left side of figure 4.4-2(c), considers the levelized annual energy cost saving. Included are all of the cases that were retained from the previous figure plus two additional cases, a low-speed diesel and a combined cycle/PFB. The two additional cases plus the steam turbine/AFB, gas turbine/PFB, and molten carbonate fuel cell/gasifier systems are the top five cases in terms of the levelized annual energy cost saving. All of the advanced cases have higher fuel energy savings and use a lower price fuel than the state-of-the-art gas turbine and hence show much higher levelized annual energy cost savings. In this particular step no systems were dropped.

The incremental capital cost versus annual operating cost saving is again considered on the right side of figure 4.4-2(c). Both new cases in this figure have ROI's above the 13 percent cutoff adopted previously. However, at this point, the combined cycle/PFB was dropped from further consideration because it showed no advantage over the gas turbine/PFB (which is the same system but without the steam bottoming cycle) in terms of any of the parameters considered here.

. In step 4, figure 4.4-2(d), the emissions saving ratio is considered. Two new cases appear in the left side of this figure, a distillate-fueled phosphoric acid fuel cell system and a distillate-fueled combined cycle. These, together with three of the cases carried over from the previous figure, make up the top five cases in terms of emissions saving ratio. The coal-fired diesel that was identified in figure 4.4-2(c) as having the highest levelized annual energy cost saving was dropped from figure 4.4-2(d) since its emissions saving ratio was negative. The other cases shown have very attractive emissions saving ratios, particularly the fuel cell systems.

Finally, on the right side of figure 4.4-2(d) the incremental capital cost versus annual operating cost saving is again considered. As shown, the two cases that use coal-derived distillate fuel have low annual operating cost saving and hence low ROI. The other four advanced systems have survived this step of the screening and are retained as the most attractive cases for this particular industrial process. These cases are shown in figure 4.4-2(e).

4.4.2 National-Basis Evaluation

Although the emphasis in the study was on the development of data on a plant basis, relative comparisons of the various advanced systems in terms of potential benefits on a national scale were also viewed as important by Lewis. For this reason, included in each contractor's effort was the task of aggregating their plant-basis results to the national scale by using simple, straightforward techniques. Included in the estimates made by the contractors for each system were the potential energy saving, emissions saving, and annual cost saving. To obtain relative comparisons among the various advanced systems, each system was considered individually and applied to every process studied without competition, and then these results were extrapolated to all of the processes of the manufacturing sector not specifically included in the study. The methodology for a NASA aggregation to a national scale that was used in evaluating and screening the advanced energy conversion systems is presented in this subsection. This was done independently of the contractors' effort, but used the contractors' plant-basis results as the input to the analysis.

For simplicity Lewis considered only those processes specifically included in the contractors' studies without extrapolating to other processes. The Lewis analyses used ROI parametrically as a factor in assessing the relative aggregated savings for the various systems in order to include industrial economics more strongly in the analyses. This turned out to be a significantly more stringent and discriminating factor than was used in the contractors' studies. Overall, the NASA approach yielded savings of a factor of nearly 2 to more than 10 lower than the contractors' results in terms of the absolute magnitude of the savings estimated. These differences resulted from differences in the specific assumptions made as well as from the more limited objective and scope of the Lewis extrapolations. The Lewis calculations provide a nearly direct comparison of the contractors' cogeneration system results. Only the potential national savings calculated by Lewis are presented in this report.

The potential market assumed by Lewis for each process was estimated as indicated in figure 4.4-3. It corresponds to projected new expansions for each process between 1985 and 1990 plus projected replacement of retired units. The retirement rate was assumed to be 2 percent of installed capacity per year.

Data for energy consumption as projected by each contractor were used to estimate the size of the potential market in each process included in that study. Results for an aggregated market that included 40 GE processes and for an aggregated market that included 26 UTC processes were then developed by Lewis for each type of energy conversion system studied.

An example of the type of data that were prepared by Lewis in evaluating potential national benefits of the advanced systems is given in figure 4.4-4. Shown is the 1990 potential fuel energy saving for the advanced steam turbine system with a coal-fired AFB furnace aggregated over 40 processes included by GE in their contracted study. The GE data for the advanced steam turbine system were used as input to the analysis, as were the GE projections of the growth of the various industries. Energy saving is shown as a function of a "hurdle" ROI required for an industrial investment in the cogeneration system. At any value of hurdle ROI in this figure it was assumed that all of the processes for which the steam turbine/AFB system achieved higher ROI would use the system in cogeneration and would achieve the plant-basis fuel energy saving calculated. The value on the ordinate of the figure shows the accumulated national fuel energy saving for all such processes.

The hurdle ROI is the minimum rate of return on an investment needed for a decision by an industrial concern to make the investment. Of course other factors would also likely be used in coming to a decision. Even though a hurdle ROI may vary from industry to industry, within companies in a given industry, and even from time to time within the same company, for simplicity the same value was assumed by NASA to be applicable to all potential industrial applications. It was felt this approach would factor industrial economics into the national-scale results while stopping short of a detailed market analysis, which was beyond the scope of the study.

The effect of hurdle ROI on potential energy saving can be seen from figure 4.4-4. If only an ROI ≥ 0 is assumed to be required, the potential national energy saving in 1990 for the steam turbine/AFB system applied to these 40 processes would be slightly greater than 200×10^{12} Btu/yr. If an ROI ≥ 10 percent were assumed to be required, only a slight reduction in potential saving would result. However, if an ROI ≥ 20 percent or ≥ 30 percent were assumed to be required, the potential saving would drop to approximately 180×10^{12} and 140×10^{12} Btu/yr, respectively.

Different energy conversion systems have a different sensitivity of energy saving to required ROI. Displays such as that shown in figure 4.4-4 were prepared for each of the advanced systems by using each contractor's plant-basis results and industrial growth projections. Figures for national savings in this report show results for slices through ROI ≥ 0 and ROI ≥ 20 percent in order to illustrate the effect of required ROI on the comparisons of advanced systems on a national scale. The methodology described provided not only a way of comparing and screening the advanced energy conversion systems, but also a way of further identifying industries where the various advanced energy conversion systems could make a significant impact on industrial energy consumption. For example, identified in figure 4.4-4 are industrial processes where large potential savings resulted for the steam turbine/AFB system in the GE study.

TABLE 4.1-1. - FUEL SPECIFICATIONS

Content	Petroleum derived		Coal derived		Coal
	Distillate	Residual	Distillate	Residual	
Sulfer, wt %	0.5	0.7	0.5	0.7	3.9
Nitrogen, wt %	0.06	0.25	[a]0.8	[a]1.0	1.0
Hydrogen, wt %	12.7	10.8	[a]9.5	[a]8.5	5.9
Ash, wt %	Negligible	0.03	0.06	0.26	9.6
Trace elements[b]	Low	High	Moderate	High	High

[a]Nominal value.
[b]Vanadium, sodium, potassium, calcium, and lead.

TABLE 4.1-2. - FUEL PRICES BASED ON DOE INPUT

Fuel	1985 Base year price, 1978 \$/MBtu	Escalation of price above inflation, percent/yr
Distillate oil[a]	3.80	1.0
Residual oil[a]	3.10	1.0
Coal	1.80	4.6 (1985-2000)
Natural gas	2.40	1.0 (after 2000)

[a]Prices for petroleum- and coal-derived liquid fuels of similar grades are assumed to be the same.

TABLE 4.1-3. - EMISSIONS GUIDELINES

[Based on 1971 Federal New Source Performance Standards for steam powerplants and on proposed NSPS for stationary gas turbines (1977).]

Pollutant	Fuel type		
	Solid	Liquid	Gaseous[a]
NO_x, lb/MBtu	0.7	[b]0.5	0.2
SO_x, lb/MBtu	1.2	0.8	0.2
Particulates, lb/MBtu	0.1	0.1	0.1

[a]Solid-fuel standards apply to systems using gas produced on site from integrated coal gasifiers.
[b]NO_x guideline for petroleum distillate is 0.4 lb/MBtu input.

TABLE 4.1-4. - CAPITAL COST ACCOUNTING CATEGORIES (ISLANDS)

General Electric Co.		United Technologies Corp.	
Item	Island	Item	Island
1	Fuel handling	1	Fuel and waste handling and storage
2	Fuel utilization and cleanup	2	Conversion system heat source
3	Energy conversion system	3	Energy conversion system
4	Bottoming cycle	4	Thermal storage
5	Heat sink[a]	5	Supplementary boiler
6	Heat rejection	6	Heat rejection
7	Balance of plant	7	Balance of plant
8	Contingency	8	Contingency

[a]e.g., supplementary boiler.

TABLE 4.1-5. - COST ADDERS

	General Electric Co.	United Technologies Corp.
Indirect labor, percent of direct labor	90	75
Contingency, percent	15	20
Engineering and fees, percent	11	15

TABLE 4.1-6. - MAJOR ASSUMPTIONS FOR CTAS ECONOMIC ANALYSES

Inflation rate	All economic calculations are inflation free[a]
Income tax rate, including Federal, state, and local income taxes, percent	50
Other local taxes and insurance, percent of capital investment per year	3
Investment tax credit (assumed to reduce tax liability in first year of operation)	10
Depreciation	Sum of year's digits; 15-year tax life
Cost of capital (after taxes), percent	5.4
Capital cost escalation above general inflation	0
Startup date (all systems assumed to start operation in that year; capital investment assumed to occur in single cash flow at that time)	1990

[a]Gives conservative results.

TABLE 4.4-1. - CHARACTERISTICS OF REPRESENTATIVE PROCESS PLANTS COMMON TO BOTH CONTRACTS

Process plant	Size, MW electric		Power-to-heat ratio[a]		Process temperature, °F	
	GE	UTC	GE	UTC	GE	UTC
Meat packing	1.9	8.7	0.28	0.34	Hot water; 250° F steam	Hot water; 300° F steam
Malt beverages	6.0	2.6	.24	.14	Hot water; 250° F steam	300° F steam
Nylon	11.0	8.2	1.63	.94	274° F steam	300°, 500°, 700° F steam
Chlorine	120.0	77.0	1.55	1.03	338° F steam	300°, 500° F steam
Alumina	30.3	31.0	.11	.19	495° F steam	500° F steam
Writing paper	50.0	33.0	.22	.22	366° F steam	Hot water; 300°, 500° F steam
Newsprint	31.3	130.0	.58	.68	366° F steam	Hot water; 300°, 500° F steam
Petroleum	52.0	34.6	.13	.14	470° F steam	500° F steam
Steel	280.0	200.0	1.05	.78	448° F steam	500° F steam

[a]For steam and hot water.

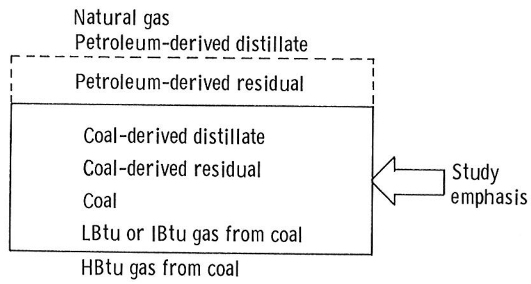


Figure 4.1-1. - CTAS fuels.

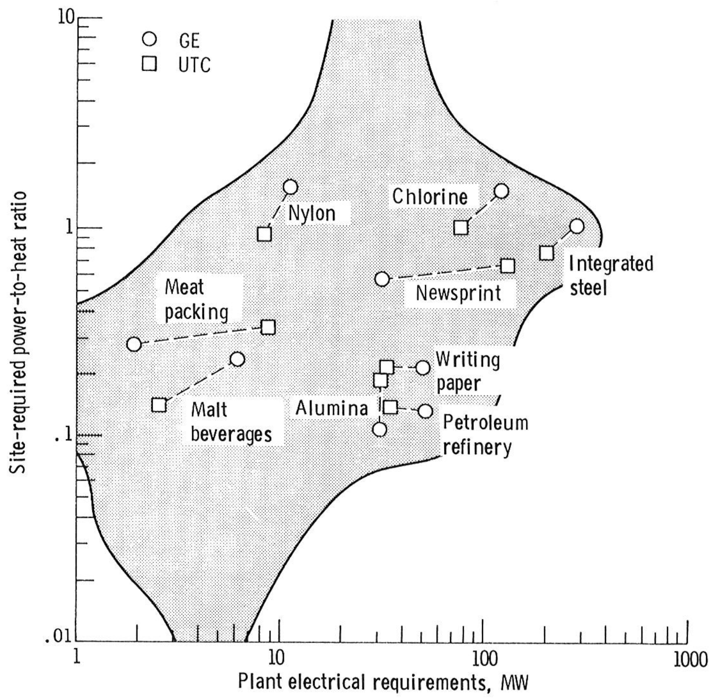
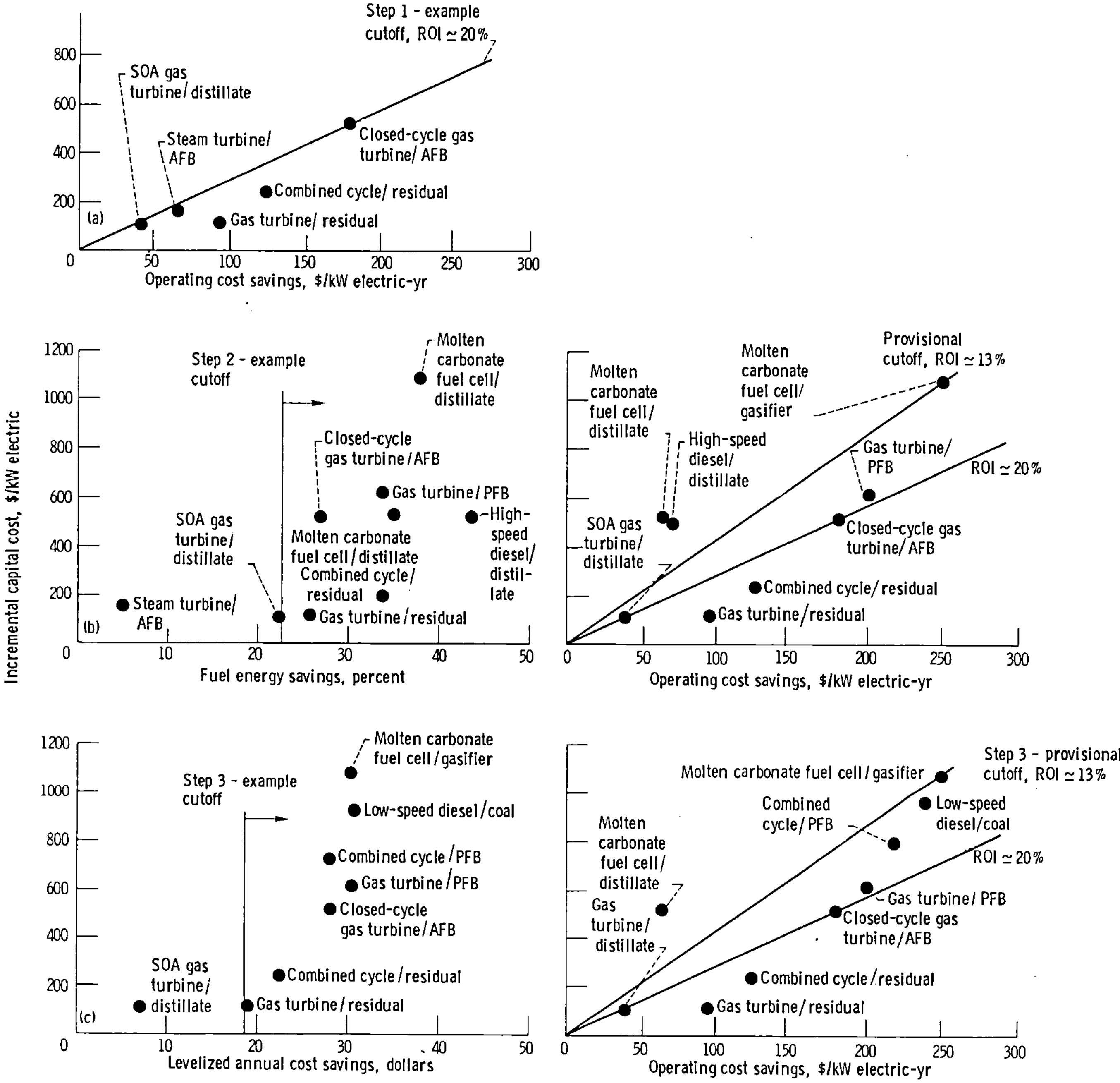
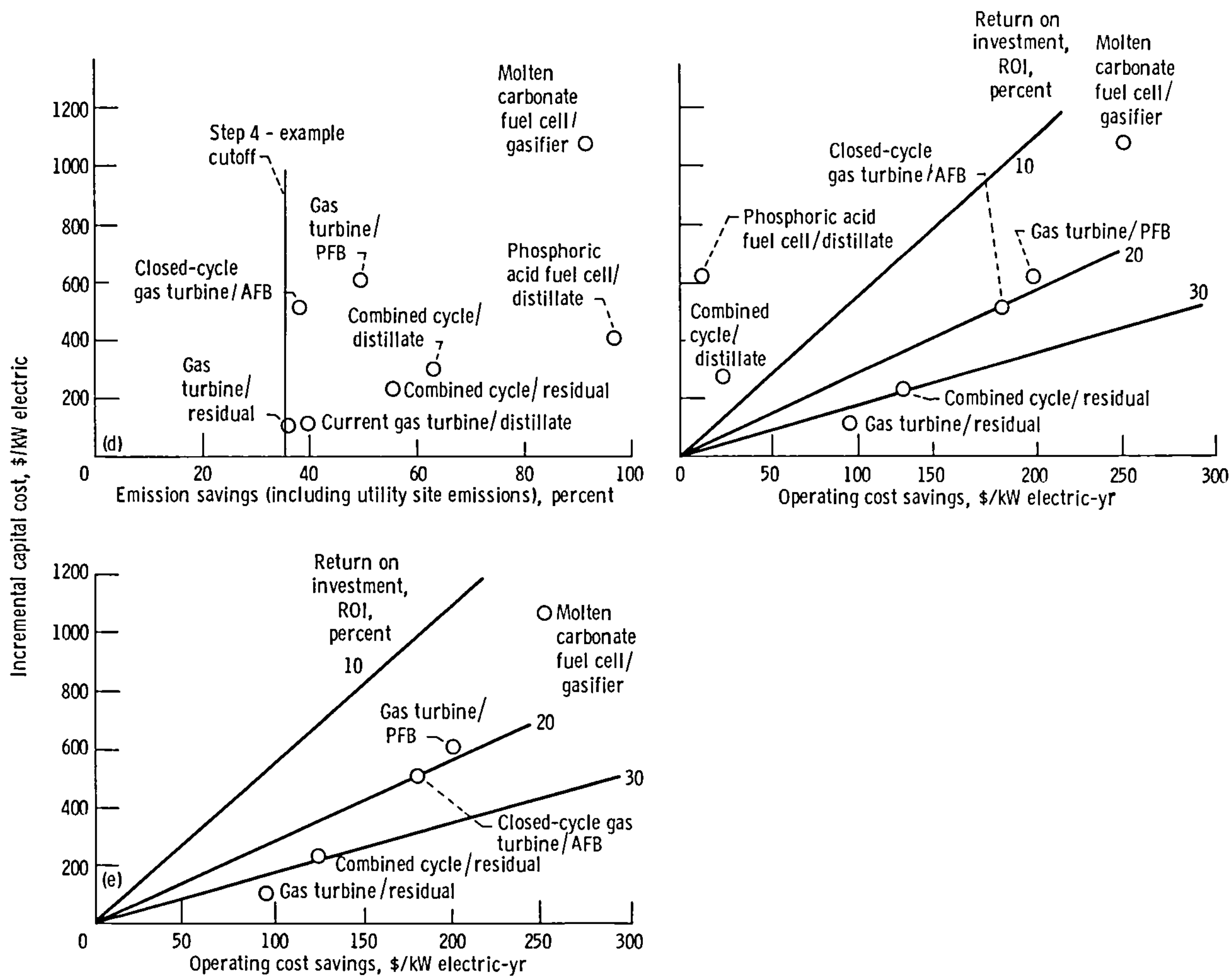


Figure 4.4-1. - Size distribution for representative processes common to both contractors.



(a) Step 1 - consider incremental capital cost and return on investment.
(b) Step 2 - consider fuel energy saving ratio.
(c) Step 3 - consider levelized annual energy cost saving ratio.

Figure 4.4-2. - Example of screening process: newsprint industry. (All values relative to noncogeneration boiler burning residual-grade, coal-derived liquid fuels and coal-fired utility. ROI denotes return on investment.)



(d) Step 4 - consider emissions saving ratio. (Low-speed diesel coal system has negative emissions savings.)
(e) Final step - choose most attractive cases.

Figure 4.4-2. - Concluded.

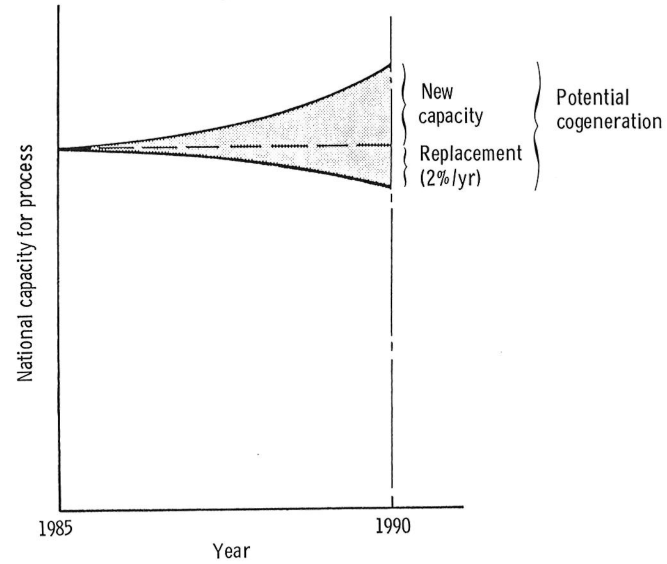


Figure 4. 4-3. - Procedure used by Lewis for estimating potential market.

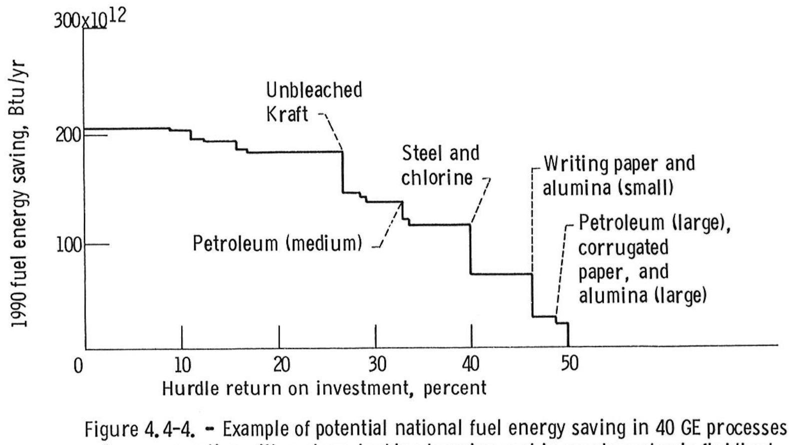


Figure 4.4-4. - Example of potential national fuel energy saving in 40 GE processes for cogeneration with a steam turbine burning coal in an atmospheric fluidized bed. (All values relative to noncogeneration boiler burning coal-derived residual liquid fuels and coal-fired utility.)

5.0 COMPARISON OF CONTRACTOR RESULTS

INTRODUCTION

Raymond K. Burns

In this section the cogeneration results of each contractor are summarized, compared, and discussed on a system-by-system basis. In each case the results are compared in enough detail to identify and explain differences in the contractors' approaches and results. Additional calculations done by NASA are included to give insight into the results or to evaluate possible changes or improvements to the cases studied. In all cases, to make broader and more consistent comparisons, the contractors' data have been used to calculate and display results that do not appear in the contractor reports.

The combinations of energy conversion system and fuel considered by each contractor are shown in table 3.2-1. In this section the system configurations and design-point parameters for each of the fuels considered are summarized and compared. The results are discussed in terms of all of the cogeneration parameters defined in section 4.3 and discussed in appendix D.

As shown in appendix D the plant-site cogeneration results of a particular system depend strongly on the required power-to-heat ratio of the process, the temperature and form of the required heat, the hours of operation per year, and the cogeneration matching strategy employed. A comparison of energy conversion systems must therefore be done for a range of processes. In this section the cogeneration results of each system are summarized and compared for a representative subset of the processes considered in CTAS. This subset is identified in section 4.4. It consists of nine processes that were studied by both contractors and that cover a range of size, power-to-heat ratio, and temperature requirements representative of the range for all of the processes studied.

In addition to the plant-site results for the nine processes, each system was examined from a national perspective by using the procedure described in section 4.4. This involved comparing potential fuel savings aggregated to a national level as a function of an assumed hurdle return on investment. Examining the potential national fuel savings allowed the percentage savings achieved by a system on a plant-site basis to be weighted by using the national energy consumption for each process considered. The hurdle ROI was varied parametrically to compare the sensitivity of potential national fuel savings of different types of systems to the required ROI. This also served to further identify attractive applications for each system.

As discussed in section 4.2 the contractors made different assumptions concerning the type of fuel used in the noncogeneration furnace. As indicated in appendix D, the type of fuel used in the noncogeneration onsite furnace has a significant effect on cogeneration parameters such as emissions saving ratio, levelized annual energy cost saving ratio, and return on investment. To make consistent comparisons, the cogeneration results discussed in this section were all compared with a noncogeneration situation where the process heat was produced on site from coal-derived residual fuel (CDL residual).

5.1 STEAM TURBINE SYSTEMS

Yung K. Choo

5.1.1 Configurations and Parameters

The major parameters and configurations of the steam turbine systems studied by each contractor are summarized in table 5.1-1. Both contractors studied state-of-the-art steam turbine systems burning residual fuel (SOA steam turbine/residual) or coal with flue gas desulfurization (steam turbine/FGD). General Electric considered two additional steam turbine systems with advanced furnaces, namely, atmospheric-fluidized-bed boiler (steam turbine/AFB) and pressurized-fluidized-bed boiler (steam turbine/PFB). Both fluidized-bed boilers have steam tubes in the bed. United Technologies also studied two advanced steam turbine systems: one with an AFB boiler and the other with a conventional boiler burning coal-derived residual oil (steam turbine/coal-derived residual) and operating at a higher throttle condition than those used for the UTC state-of-the-art steam turbine systems.

Configurations of the steam turbine systems studied by the contractors are shown in figure 5.1-1. Contractors considered different configurations by selecting different turbine types for the study. Each configuration is characterized by a different turbine. GE selected noncondensing back-pressure turbines that operate at 1465 psia/1000° F and 850 psia/825° F throttle conditions. The back-pressure turbine exhausts steam at the pressure required by the process. If a process needs steam at more than one condition, GE uses a saturation pressure corresponding to a weighted average of the process steam temperatures as an approximation. UTC selected a single-extraction condensing turbine that operates at 1200 psia/950° F throttle condition for the state-of-the-art steam turbine systems and at 1800 psia/1050° F throttle condition for the advanced systems. Ten discrete combinations of extraction pressure and extraction flow rate were considered. UTC called each combination a design option. A design option has either 65-psia or 615-psia extraction pressure and one of the five extraction flow rates - maximum extraction (about 90 percent) and 75, 50, 25, and 10 percent extraction of the throttle steam flow. The 65-psia extraction is for the 300° F steam; the 615-psia extraction is for the 500° or 700° F steam. The steam remaining after the extraction continues to expand through the low-pressure section of the turbine and thus generates additional power. Latent heat of the exhaust steam is removed in the condenser, which operates at 3 psia.

Each contractor assumed different system parameters. GE assumed 85 percent efficiency for all steam boilers except the PFB boiler. They also assumed that this efficiency included auxiliary losses. UTC assumed a different efficiency for each type of boiler. They assumed 88 percent for the oil-fired boiler, 84 percent for the AFB boiler, and 85 percent for the coal-fired boiler with FGD. Parasitic thermal and electrical loads were treated separately from the boiler efficiency. GE used a constant turbine efficiency of 80 percent for the 1465 psia/1000° F throttle and a size range between 7.5 and 100 MW electric. They also used a constant 78 percent for the 865 psia/825° F throttle and a size range between 5 and 50 MW electric. UTC assumed a constant turbine efficiency of about 80 percent for a system of 30 MW electric or larger and a decreasing turbine efficiency as the size decreased from 30 to 0.6 MW electric.

5.1.2 Cogeneration System Performance

5.1.2.1 Effect of Configuration and Parameters

The performance results of the steam turbine systems studied by the contractors are significantly different, as is shown later in this section. The differences were caused by the selection of different configurations and parameters as summarized here:

(1) Back-pressure noncondensing turbine (GE) versus single-extraction condensing turbine (UTC)
(2) Constant turbine efficiency (GE) versus varying turbine efficiency with size (UTC)
(3) Steam exhaust at process steam pressure (GE) versus steam extraction at two preselected pressures - 65 and 615 psia (UTC)
(4) Difference in boiler efficiency
(5) Difference in auxiliary power requirement
(6) Differences in availability and amount of byproduct fuel

The effect that each difference had on the NASA calculated results is discussed, and why the performances of the contractors' steam turbine systems differed is explained. (The performance results of the GE and UTC systems for a representative subset of nine CTAS industries are then discussed.)

Cogeneration performance characteristics of the two turbine types are compared in figure 5.1-2. The following system parameters were constant:

(1) 1465 psia/1000° F throttle conditions
(2) 85 Percent boiler efficiency
(3) 80 Percent turbine efficiency
(4) 170° F condensate return and makeup water
(5) 240° F final feedwater temperature
(6) 65-psia extraction pressure for the single-extraction turbine
(7) 65-psia exhaust pressure for the back pressure noncondensing turbine
(8) Zero auxiliary power
(9) Use of a deaerator heater

The dashed line in figure 5.1-2 shows the performance of the back pressure turbines for exhaust pressures from 30 to 680 psia (saturation temperature from 250° to 500° F). Each location on the curve represents a turbine design for the back pressure corresponding to the saturation temperature indicated in the figure. Comparison of the dashed lines in figure 5.1-2 and figure D-1 in appendix D indicates that the power-to-heat ratio and the electrical efficiency of the back-pressure turbine system decrease with increasing back pressure. The reason in that a lower fraction of the available energy is used in the turbine to generate power and more heat is available for an industrial process at a higher back pressure. This curve is almost identical to the GE results for the 1465 psia/1000° F throttle, exclusive of the results of the steam turbine PFB system, and has a nearly constant heat recovery factor (AR) of about 0.8.

The solid line in figure 5.1-2 represents the performance of a single-extraction condensing turbine for the extraction pressure of 65 psia (300° F saturation temperature) and the parameters defined above. A single-extraction turbine can operate over a wide range of power-to-heat ratio by changing the steam extraction rate. The performance curve indicates that the fuel energy

saving ratio (FESR) (refer to section 2.5, Definition of Terms) approaches zero as the extraction rate becomes small. The reason is that this system approaches the noncogeneration case as the extraction rate approaches zero. Referring to appendix D, note that the heat recovery factor approaches zero as the extraction rate approaches zero since all the heat in the exhaust steam is rejected in the condenser. Although UTC considered five extraction rates, they used the two highest extraction rates in matching the steam turbine system with most CTAS industries studied. The performance point of the maximum extraction rate (88 percent of throttle flow in the NASA calculation) is close to that of the back-pressure turbine. But the performance of the 75-percent-extraction-rate case is substantially different in both FESR and system power-to-heat ratio. The difference in FESR will become even greater when the two steam systems are used for an industry with a power-to-heat ratio closer to that of the back-pressure turbine system.

The effect of size (turbine efficiency) on performance is shown in figure 5.1-3. The effect of turbine efficiency was examined with the UTC single-extraction turbine only, since GE assumed no efficiency variation with turbine size. For the same system parameters selected above, the turbine efficiency was reduced from 80 percent to 70 and 60 percent in order to examine sensitivity. For a constant extraction rate of 75 percent the heat recovery factor remains at a nearby constant value of about 68 percent (fig. D-1), but the system electrical efficiency, power-to-heat ratio, and FESR are all reduced substantially as the turbine efficiency is reduced. Performance differences between the contractors' results caused by small system size would be substantial for 10-MW-electric or smaller systems. GE used constant 80 and 78 percent turbine efficiencies depending on the throttle condition; UTC varied turbine efficiency on the basis of the system performance data provided for the 6- and 18-MW-electric systems by its subcontractor, DeLaval.

The effect of UTC's approach of extracting steam only at 65 or 615 psia is examined in figure 5.1-4. To illustrate this effect as contrasted with extracting at process steam pressure, a process that needs steam at 350° F was considered. One approach is to extract steam at 135 psia for 350° F condensing temperature. When this approach is used in the single-extraction turbine, the performance is represented by the solid curve in the figure. (The expected result of the GE back-pressure turbine for the 135-psia exhaust is also shown in the figure.) In the UTC approach, steam extraction is allowed only at one of the two preselected pressures (i.e., 65 or 615 psia). Therefore the 65-psia extraction cannot satisfy the 350° F condensing temperature required by the process, and the steam should be extracted at 615 psia. The results for the 615-psia extraction are shown by the dashed curve in figure 5.1-4. Comparison of those curves indicates that the performance penalty caused by the UTC approach could be significant when the process steam pressure needs to be just slightly higher than 65 psia.

The effect of boiler efficiency is shown in figure 5.1-5. The FESR improved as the boiler efficiency increased, since the heat recovery factor and the system electrical efficiency increase with increasing boiler efficiency (fig. D-1).

The effect of the auxiliary losses was examined because the two contractors assumed different values. The auxiliary loss assumed for the UTC steam turbine system with flue gas desulfurization (steam turbine/FGD system) is substantially higher than that assumed for the GE steam turbine/FGD system. GE

assumed 80 percent boiler efficiency including auxiliary losses; UTC assumed 85 percent boiler efficiency without including auxiliary losess. UTC also included 10 percent of generator output as auxiliary losses. Figure 5.1-5 also shows the effect of auxiliary losses. The auxiliary power losses cause the system power efficiency to drop and hence reduce FESR. UTC's low FESR results for the steam turbine/FGD system are largely affected by the high auxiliary losses expected for the system.

Finally, the effect of the use of byproduct fuels is shown by some industry cases in figure 5.1-6. The use of free byproduct fuel saves other fuel and therefore improves FESR. The levelized annual energy cost saving ratio (LAECSR) also improves from the fuel saving. There are differences, however, between the contractors' industry data for the availability and amount of the byproduct fuels. And this difference in the industry data, in turn, affects the system FESR and LAECSR in the contractors' studies.

Only GE studied the steam turbine system with a pressurized fluidized bed (steam turbine/PFB) and only with a single system configuration. Therefore NASA additionally considered three configurations for the steam turbine/PFB system. The first configuration was identical to the one selected by GE and is shown in figure 5.1-1(c). The second and third configurations are shown in figures 5.1-7 and 5.1-8. The same PFB furnace system studied in phase 2 of the Energy Conversion Alternatives Study (ECAS) was selected for this preliminary calculation. Since the PFB size appropriate for this study might be obtained by reducing the number of bed cells from an ECAS module, only the configuration was changed for cogeneration.

In the first steam turbine/PFB configuration (fig. 5.1-1(c)) all of the steam is generated for a back-pressure turbine that operates at 1435 psig/1000° F throttle conditions. In the second configuration (fig. 5.1-7) steam is produced at two pressures in two parallel loops. The high-pressure steam Q_1 is generated for the steam turbine at 1435 psig/1000° F, and the low-pressure steam Q_2 is generated at 300 psig and is sent directly to an industrial process. Let Q_T be the heat in the total steam generated at both high and low pressures. Then $0 \leq (Q_1/Q_T) \leq 1$ in this case. When $Q_1/Q_T = 1$, the second configuration is equivalent to the first configuration, and when $Q_1/Q_T = 0$, it is equivalent to the UTC gas turbine/PFB, which is described in section 5.3. In configuration 3 (fig. 5.1-8) the gas turbine shaft power is matched with the power required by the compressor by reducing the gas turbine inlet temperature. This can be accomplished by adding more heat transfer surfaces in the PFB convection space. The combustion product leaves the PFB module at about 800° F, which is substantially lower than the 1600° F required for the previous two configurations. Gas cleanup cost might be reduced in this configuration because of the substantially lower temperature for particulate removal. Lower gas temperature also reduces the alkali vapor concentration and therefore reduces the level of hot corrosion on gas turbine blades.

The parameters that were assumed for the NASA steam turbine/PFB cases are summarized in the following table:

Configuration	Back pressure, psig	Gas turbine inlet temperature, °F
1	15-300	1600
2	300	1600
3	50	800

Performance characteristics for these configurations are presented in figure 5.1-9. In configuration 1 the power-to-heat ratio and power system efficiency decrease as the back pressure increases, as in the back-pressure steam turbine with a conventional furnace (fig. 5.1-2). The performance of configuration 2 varies between that for configuration 1 with 300-psig back pressure and the gas turbine/PFB case as the heat ratio between the two parallel steam loops is changed. The performance of configuration 2 is almost identical to that of the back-pressure steam turbine with AFB and other state-of-the-art furnaces. In configuration 3 a back pressure of 50 psig is used. Even though the gas turbine does not produce any net power, the steam turbine generates more power with the additional heat recovered in the PFB convection space. The power-to-heat ratio of configuration 3 is almost identical to that of configuration 1 with 300-psig back pressure and is approximately two-thirds of the value of configuration 1 with 50-psig back pressure. For all the changes in configuration and parameters the heat recovery factor remains at about 0.8. Power system power-to-heat ratios are between 0.1 and 0.45 for the steam turbine/PFB cases considered.

5.1.2.2 Fuel Energy Saving Ratio

Figure 5.1-10 shows the ratio of power to process heat produced by the GE and UTC systems versus the potential fuel energy saving that could be achieved if the system power-to-heat ratio matched the process needs. If the site-required power-to-heat ratio differs from the value provided by the system, the fuel saving in most cases will be lower than indicated here unless free by-product fuel from the process is used. Each GE curve shows the locus of performance for a range of turbine back pressure between 30 and 680 psia. Each UTC curve shows the performance of the extraction turbine at either 65- or 615-psia extraction pressure and a range of steam extraction rate. Not all of the UTC performance curves for the 615-psia extraction are shown.

Performance results of the steam turbine systems studied by both contractors are shown in figure 5.1-11 for a process that requires a power-to-heat ratio that is different from the power system ratios. The cogeneration performance of systems is discussed for such mismatching cases in appendix D. The process requires 30-MW-electric power, 300° F steam, and a power-to-heat ratio of 0.25. It provides no byproduct fuel. Note that UTC's approach of using either 65- or 615-psia extraction has no effect on the results because both the GE and UTC systems supply 300° F steam at 65 psia. The FESR of the GE back-pressure turbines is the highest value among all of the results. The single GE point represents GE's steam turbine/petroleum residual, steam turbine/FGD, and steam turbine/AFB systems since they assumed the same system parameter values for all three systems.

The FESR results of the four UTC extraction condensing steam turbines are also shown in the figure. The UTC advanced steam turbine/AFB system has relatively low auxiliary losses and a high throttle condition; the steam turbine/petroleum residual system has high boiler efficiency and low auxiliary losses. They both have FESR values between those for the advanced steam turbine/coal-derived residual and steam turbine/FGD systems. The highest FESR is achieved by the advanced steam turbine/coal-derived residual system when maximum steam is extracted. Relatively low auxiliary losses associated with an oil-fired boiler and a higher boiler efficiency of 88 percent also contribute to the high FESR. If 75 percent of throttle steam is extracted as in

the other three UTC steam systems, the result will approach the FESR of the steam turbine/petroleum residual system. The UTC steam turbine/FGD system has the lowest FESR because of high auxiliary losses and the relatively low boiler efficiency used by UTC.

Fuel energy saving ratio results for the steam turbine systems matched to the nine representative industries are shown in figure 5.1-12. The processes are generally listed in ascending order of power-to-heat ratio from left to right. The characteristics of these processes are listed in section 3.2. UTC results for the petroleum, alumina, and integrated steel processes were modified by NASA to exclude the direct-heat requirements in order to better represent cogeneration results of the systems and to compare the contractors' results on a consistent basis. The direct heat specified by UTC for the integrated steel is the heat that could be provided by the coking coal. The UTC alumina case requires burning a specified clean fuel for the direct heat to calcine the alumina. The UTC petroleum case also requires a substantial amount of direct heat. Performance and economic results for the three UTC industries were changed as required for the modification.

Comparison of contractors' results when no power export is allowed (fig. 5.1-12(a)) indicates that the GE steam turbine systems achieved higher FESR values for almost all of the representative industries. This is due to the differences in the system configurations and parameters and their effect on performance, as discussed earlier.

Comparison of the results by industries shows that high FESR results can be achieved by the steam turbines in malt beverage and meat packing. These industries have a good match in power-to-heat ratio with the steam turbine systems and require steam at low temperatures. Bleached Kraft shows also high FESR because of a good match with the systems, moderate steam temperature, and free byproduct fuel. Petroleum and alumina have good power-to-heat ratios to be matched with steam turbines, but they have lower FESR's than writing paper (bleached Kraft) because of their need for high-temperature steam (470° to 495° F in GE; 500° F in UTC). Newsprint, integrated steel, nylon, and chlorine need power-to-heat ratios of 0.58 to 1.63. These four industries show low FESR results because of substantial mismatch with the steam turbine systems, which have low power-to-heat ratios.

The FESR results when power export is allowed are shown in figure 5.1-12(b). Power export cases are cross hatched. Slight improvements are shown in the industries that have power-to-heat ratios lower than the system power-to-heat ratios. The GE steam turbine/PFB system has the highest power-to-heat ratios of the steam turbine systems and shows clear improvement with power export in several industries.

5.1.2.3 Emissions Saving Ratio

The EMSR results are shown in figure 5.1-13. The results shown correspond to the sum of oxides of nitrogen (NO_x), oxides of sulfur (SO_x), and particulate emissions. The EMSR values are closely related to the FESR values because higher FESR means less fuel input to the system. Comparison of figures 5.1-13 and 5.1-12 indicates that the EMSR results improve with power export in those industries in which the FESR results improve with power export.

The emissions characteristics in pounds per million Btu of fuel energy consumption assumed by the contractors for the systems studied are shown in table 5.1-2. The emissions characteristics assumed by the two contractors are in close agreement for the common system subgroups.

The steam turbine/residual system shows higher EMSR results than the steam turbine/FGD system, which burns coal. Among the coal-fired systems the steam turbine/AFB and the steam turbine/PFB systems achieved relatively high EMSR results because of their high FESR values and the assumption of better emissions characteristics than those assumed for the steam turbine/FGD system.

5.1.2.4 Capital cost

Capital cost estimates for the steam turbine systems are compared in figure 5.1-14 for 10- and 30-MW-electric systems with recovery of waste heat as 300° F steam. Each contractor estimated the costs according to the cost accounts described in section 4.1. The bar graphs in the figure include all fuel handling, storage, and processing equipment and a supplementary boiler to provide a power-to-heat ratio of 0.25. The capital costs of 30-MW-electric systems excluding the supplementary boiler cost are indicated by arrows.

Both contractors' estimates agree that the steam turbine/residual system requires substantially lower capital than the coal-fired systems and that the steam turbine/FGD system is the most expensive. GE steam turbine systems with AFB and PFB furnaces show similar capital costs when supplementary boiler costs are not included. The steam turbine/PFB system requires a larger supplementary boiler than the steam turbine/AFB system, since the steam turbine/PFB system has a higher power-to-heat ratio and causes higher thermal mismatch. In the figure, cost categories 1 and 2 (furnace subsystem including fuel and waste handling) were combined for valid cost comparison because one contractor includes flue gas desulfurizer cost in category 1 and the other includes it in category 2. Note that a major contribution to the total capital cost difference is the furnace subsystem costs.

To illustrate the difference further, the furnace subsystem costs of the steam turbine systems for 30 MW electric and 300° F steam are compared in figure 5.1-15. The costs are in dollars per kilowatt of the furnace thermal duty. The contractors' estimated costs for the coal/FGD furnace agree very well, but there are some differences in the residual furnace and coal/AFB furnace costs.

5.1.2.5 Economics

The incremental capital cost is plotted versus levelized operating cost saving for the steam turbine systems for nine representative industries in figures 5.1-16 to 5.1-20. Also shown in the figures are lines corresponding to constant ROI values. In each figure the origin corresponds to the non-cogeneration situation, where required power is purchased from a utility and onsite steam is produced in a residual fuel-fired boiler. Since the power requirements of the processes vary considerably (table 4.4-1), the incremental capital cost and levelized operating cost saving are expressed per unit of site power required. As noted by data-point shape (circle, triangle, or square), cogeneration cases may be sized to match the site power requirement or to import or export power.

GE steam turbine systems show higher ROI results than the UTC systems in several industries mainly because they achieve higher operating cost savings through the higher fuel energy savings, as discussed in the performance part of this section. The GE steam turbine systems achieve high FESR values in the meat packing and malt beverage industries, but they cannot achieve high ROI's because of the low operating cost savings caused by the low annual load factors of the two GE processes. Industries such as chlorine, newsprint, and steel require higher power-to-heat ratios than those provided by the energy conversion systems and show relatively lower FESR results than the better matching industries. But the steam turbine/residual and steam turbine/AFB systems show high ROI results in those industries using the power-import strategy because of the low incremental cost requirements.

Figures 5.1-16 and 5.1-18 show that the steam turbine systems burning residual fuel have relatively low operating cost savings but at the same time require smaller incremental capital costs than the coal-fired systems. Figures 5.1-17, 5.1-19, and 5.1-20 show the results for the coal-fired systems. These systems achieve higher operating cost savings than the residual-fueled systems by burning cheaper fuel, but they require higher incremental capital costs. Among the coal-fired steam turbine systems, the steam turbine/AFB systems show the most attractive ROI results because they require lower incremental capital costs and have operating cost savings similar to or higher than those of PFB and FGD systems. The GE steam turbine/PFB system has slightly lower ROI values than the GE steam turbine/AFB system because of its slightly higher incremental capital cost. The UTC steam turbine/FGD system shows very low ROI results because of its high incremental costs and relatively small operating cost saving as a coal-fired system. It should be pointed out that the two contractors assumed significantly different auxiliary powers for their steam turbine/FGD systems. This was a major contributing factor in their different operating cost savings.

The other economic parameter used in CTAS to combine the effects of capital and operating cost is the percent savings in levelized annual energy cost (section 4.3). The levelized annual energy cost saving ratios (LAECSR) for the nine representative industries are presented in figure 5.1-21. It is clear from the results that fuel type affects the LAECSR more than the capital cost does. The coal-fired systems show substantially better results than the residual-fueled systems.

The GE cases achieve higher LAECSR's mainly because of their higher FESR's. The steam turbine/residual systems have higher FESR's than the coal-fired steam systems, but they have significantly lower LAECSR's because the liquid fuel is more expensive than coal. Part of the gain in the LAECSR in the GE coal-fired systems comes from replacing the expensive liquid fuel for the noncogeneration boiler with the cheaper coal for the supplementary cogeneration boiler. GE used the same type of fuel in the onsite power system and the supplementary boiler.

GE coal-fired steam turbine systems show high LAECSR's in the petroleum, alumina, and writing paper industries because they use coal and have higher FESR performance. GE's fuel switching from residual fuel for the noncogeneration boiler to coal for the cogeneration supplementary boiler contributes to the higher LAECSR's achieved in the petroleum and alumina industries. The LAECSR's for meat packing are very small or negative because of the very low annual load factor. Low LAECSR's in the high-power-to-heat-ratio industries

are due to low FESR's caused by system-industry mismatch. Slight gains in the LAECSR's by the GE systems with power export are shown in figure 5.1-21(b). UTC results do not show any improvement with power export because the gain in FESR from power export is not compensated for by the capital cost increase associated with the larger system needed for export.

Relative national fuel saving. - Energy saving aggregated to a national basis is plotted as a function of hurdle ROI in figures 5.1-22 to 5.1-24. The procedure used to evaluate these curves is described in section 4.4. It was assumed for each system that 100 percent implementation in new-capacity additions or retirement replacements would occur between 1985 and 1990 in each process where the results yielded an ROI greater than the hurdle rate shown. Only processes specifically studied by each contractor were considered: Data plotted are intended to illustrate the comparative potential savings versus ROI requirement, and they are not valid as an illustration of the absolute magnitude of the savings. Only the results for non-power-export cases are shown in the figure since changes in results by power export are small because of the relatively low power-to-heat ratio of the steam turbine system.

As expected, the GE steam turbine systems show substantially higher potential national energy savings than the UTC systems. Results for both contractors' steam turbine/residual (fig. 5.1-22) and steam turbine/AFB (fig. 5.1-24) systems indicate that the potential national energy saving for an ROI hurdle rate of 20 percent is more than 90 percent of what it would be if zero hurdle rate was considered. The potential national energy saving that can be achieved by the GE steam turbine/FGD system at an ROI hurdle rate of 20 percent is more than 50 percent of that if zero hurdle rate is considered. The UTC steam turbine/FGD system did not achieve an ROI greater than 20 percent in any CTAS industry.

5.1.3 Summary

The range of results achieved by the steam turbine systems for a representative subset of nine industries is presented in table 5.1-3. Overall comparison of the GE and UTC results indicates that the FESR, LAECSR, EMSR, and ROI values of GE steam systems are significantly higher than those of the UTC steam systems. The difference in the contractors' FESR results stems from the differences in the system configuration, system parameters, and analysis approaches used by the two contractors as discussed in detail in the previous section. The EMSR, LAECSR, and ROI results are affected by the FESR results.

The tabulated data show that the steam turbine systems have very attractive application in the writing paper industry. In addition, the steam turbine systems also have reasonably attractive applications in the corrugated paper and boxboard industries. This is because the three paper industries require steam at moderate temperatures, provide free byproduct fuel, and require low power-to-heat ratios (between 0.14 and 0.22) that match well with the energy conversion systems. Steam turbine systems are not good cogeneration performers in terms of FESR for industries that require power-to-heat ratios greater than 0.4. But with the power-import strategy the steam systems require small incremental capital cost and could achieve good ROI results in the chlorine, newsprint, and steel industries, which require high power-to-heat ratios.

Note that the cogeneration system performance is sensitive to process steam pressure. Also, the performance of the extraction turbine is greatly affected by the steam extraction rate. Even though the UTC extraction condensing steam turbines show relatively low performance results, they have load-following capability, which the back-pressure turbine system and other CTAS systems do not have. Those systems have the potential to perform better than the UTC systems by using higher extraction rate and lower extraction pressure wherever possible. However, the results for the GE back-pressure turbine systems might be somewhat optimistic in some industries, considering the fact that GE assumed a relatively low auxiliary power requirement by the steam systems and assumed no turbine-generator performance change with size.

TABLE 5.1-1. - STEAM TURBINE SYSTEM CONFIGURATIONS STUDIED

Parameter	General Electric	United Technologies Corp.
All steam turbine systems		
Turbine type	Back pressure (noncondensing)	Single extraction (condensing)
Extraction pressure, (supplemental calculation for process steam pressures), psia	----------------------------------	65, 615
Back pressure, psia	Any pressure between 30 and 680 as process needs	------------------------------
Condenser pressure, psia	----------------------------------	3
Steam extraction rates, percent	----------------------------------	90, 75, 50, 25, and 10 of throttle flow
Turbine-generator efficiency, percent	80 for 1465 psia/1000° F throttle; 78 for 865 psia/825° F throttle	Varied with size under 30 MW; 80[a] above 30 MW
SOA steam turbine/residual		
Fuel	Petroleum and coal-derived residual	Petroleum-derived residual
Boiler efficiency, percent	85	88
Throttle condition, psia/°F	1465/1000, 865/825	1200/950
SOA steam turbine/FGD		
Fuel	Coal	Coal
Boiler efficiency, percent	85	85
Throttle condition, psia/°F	1465/1000, 865/825	1200/950
Advanced steam turbine/residual		
Fuel	----------------------------------	Coal-derived residual
Boiler efficiency, percent	----------------------------------	88
Throttle condition, psia/°F	----------------------------------	1800/1050
Advanced steam turbine/AFB		
Fuel	Coal	Coal
Boiler efficiency, percent	85	84
Throttle condition, psia/°F	1465/1000, 865/825	1800/1050
Bed temperature, °F	1550	1550
Advanced steam turbine/PFB		
Fuel	Coal	------------------------------
Throttle condition, psia/°F	1456/1000, 865/825	------------------------------
Bed temperature, °F	1750	------------------------------

[a]NASA estimate based on contractor's overall plant efficiency at zero extraction and assumed values of 85, 98, and 4 percent for boiler efficiency, generator efficiency, and auxiliary loss, respectively.

TABLE 5.1-2. - STEAM TURBINE SYSTEM EMISSION CHARACTERISTICS

	General Electric	United Technologies Corp.
	Emissions, lb/10^6 Btu	
SOA/steam turbine/petroleum		
SO_x	0.75	0.76
NO_x	.22	.50
Particulate	.016	.016
SOA/steam turbine/FGD		
SO_x	1.2	1.2
NO_x	.7	.7
Particulates	.1	.1
Advanced steam turbine/coal-derived residual		
SO_x	----	0.824
NO_x	----	.50
Particulates	----	.10
Advanced steam turbine/AFB		
SO_x	1.2	----
NO_x	.15	----
Particulates	.03	----

TABLE 5.1-3. - RANGE OF RESULTS FOR STEAM TURBINE SYSTEMS USED WITH NINE REPRESENTATIVE INDUSTRIES

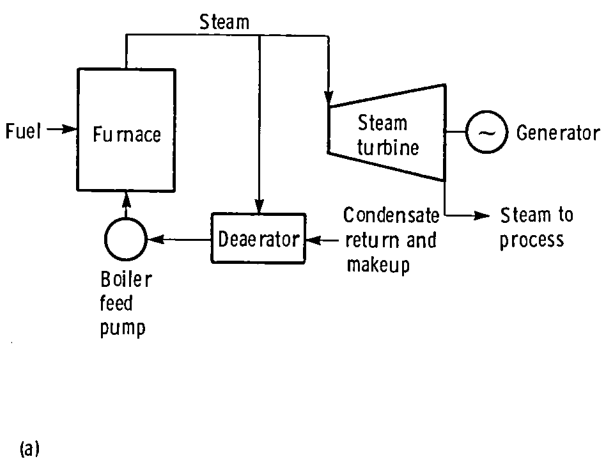
(a) No power export allowed

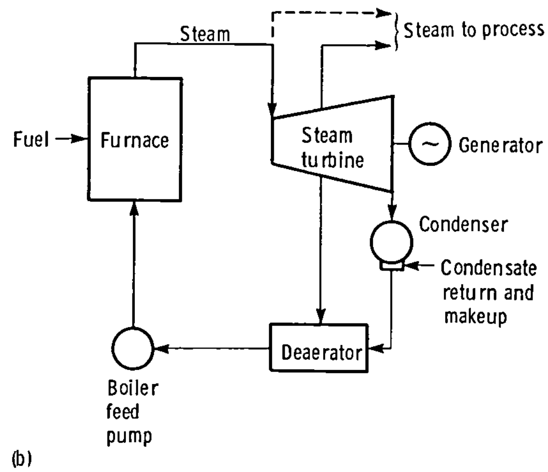
Energy conversion system subgroup	Contractor	Fuel energy saving ratio, FESR	Industry with maximum FESR	Emission saving ratio, EMSR	Industry with maximum EMSR	Levelized annual energy cost, LAEC	Industry with maximum LAEC	Return on investment, ROI, percent	Industry with maximum ROI
State-of-the-art systems									
Steam turbine/residual	GE	6-29	Writing paper	Negative to 22	Writing paper	6-30	Writing paper	0-50+	Petroleum; aluminum; writing paper; integrated steel
	UTC	1-13	Malt beverage	Negative to 6	Writing paper	2-39 [a]28	Integrated steel; writing paper	0-29	Chlorine
Steam turbine/FGD	GE	6-29	Writing paper	Negative to 35	Writing paper; petroleum	3-21	Writing paper	0-32	Petroleum
	UTC	0-8	Malt beverage	Negative to 15 [a]13	Petroleum; writing paper	Negative-4	Integrated steel	1-17	Chlorine
Advanced systems									
Steam turbine/coal-derived residual	UTC	2-14	Meat packing	Negative to 7	Writing paper	7-32 [a]27	Integrated steel; writing paper	0-30	Chlorine
Steam turbine/AFB	GE	6-29	Writing paper	Negative to 41	Writing paper	8-37	Writing paper	0-48	Petroleum
	UTC	1-15	Writing paper	1-32 [a]27	Petroleum; writing paper	0-28 [a]25	Integrated steel; writing paper	5-34	Chlorine
Steam turbine/PFB	GE	11-30	Writing paper	4-32	Writing paper; petroleum	16-43	Writing paper	0-30	Petroleum

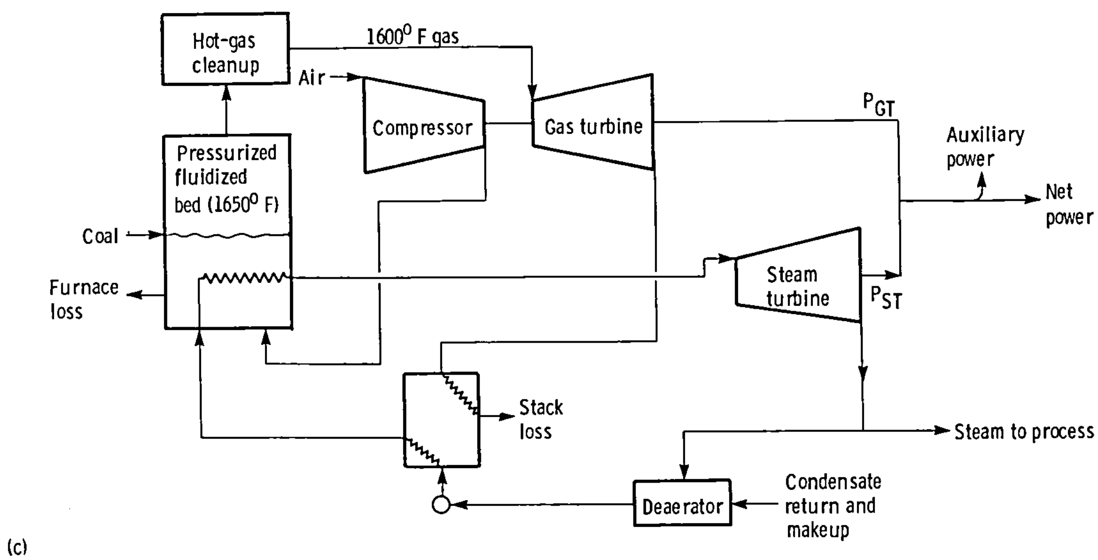
(b) Power export allowed

Energy conversion system subgroup	Contractor	Fuel energy saving ratio, FESR	Industry with maximum FESR	Emission saving ratio, EMSR	Industry with maximum EMSR	Levelized annual energy cost, LAEC	Industry with maximum LAEC	Return on investment, ROI, percent	Industry with maximum ROI
State-of-the-art systems									
Steam turbine/residual	GE	6-29	Writing paper	Negative to 22	Writing paper	6-30	Writing paper	0-50	Petroleum; aluminum; writing paper; integrated steel
	UTC	0-16	Malt beverage	Negative to 6	Writing paper	2-39 [a]28	Integrated steel; writing paper	0-29	Chlorine
Steam turbine/FGD	GE	6-29	Writing paper	Negative to 35	Writing paper; petroleum	3-21	Writing paper	0-32	Petroleum
	UTC	0-11	Malt beverage	Negative to 15 [a]13	Petroleum; writing paper	Negative-4	Integrated steel	1-17	Chlorine
Advanced systems									
Steam turbine/coal-derived residual	UTC	0-14	Meat packing	Negative to 7	Writing paper	7-32 [a]29	Integrated steel; writing paper	0-30	Chlorine
Steam turbine/AFB	GE	6-29	Writing paper	Negative to 41	Writing paper	8-37	Malt beverage; writing paper; meat packing	0-50+	Petroleum
	UTC	0-15	Writing paper	Negative to 32	Writing paper; petroleum	0-28 [a]25	Integrated steel; writing paper	0-34	Chlorine
Steam turbine/PFB	GE	11-36	Writing paper	Negative to 32	Petroleum	16-51	Writing paper	0-39	Petroleum Alumina

[a]Second most attractive application.







(a) GE back-pressure steam turbine.
(b) UTC extraction steam turbine.
(c) GE steam turbine/PFB (also NASA supplementary case 1).

Figure 5.1-1. - Schematics of steam turbine systems.

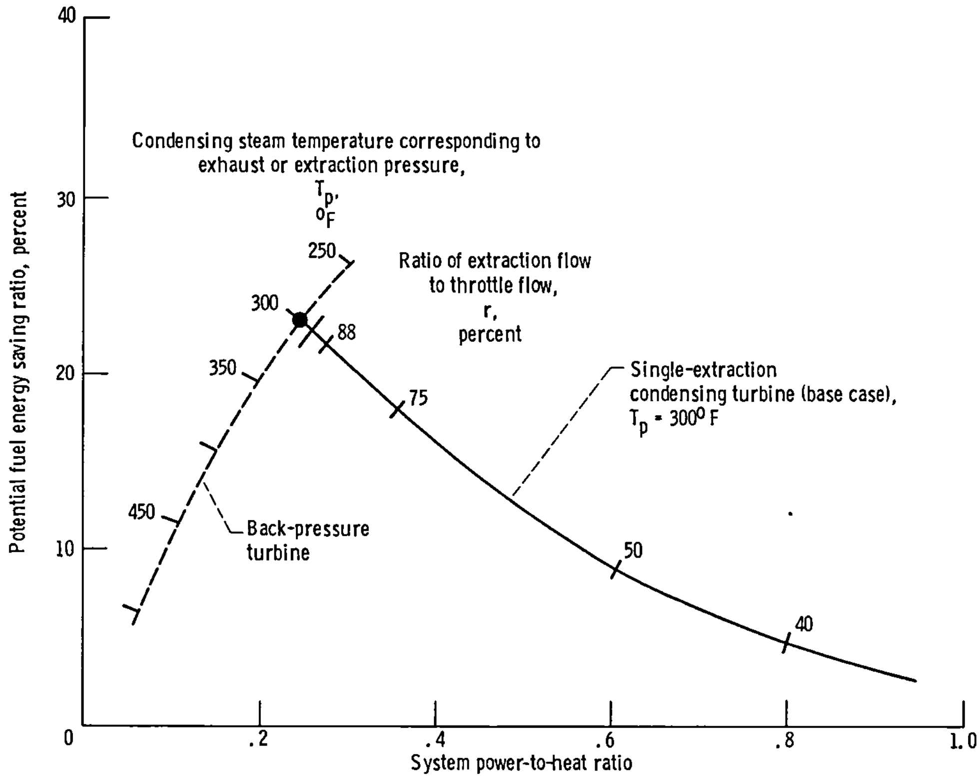


Figure 5.1-2. - Cogeneration performance characteristics of two steam turbine systems (NASA calculation). (For noncogeneration case: boiler efficiency, 88 percent; utility efficiency, 32 percent.)

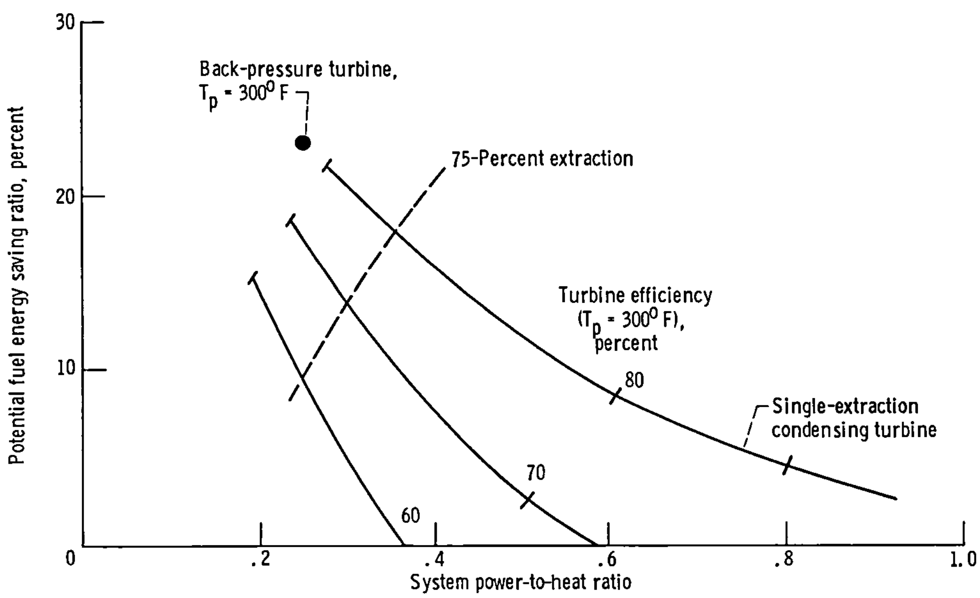


Figure 5.1-3. - Effect of turbine efficiency on power system performance (NASA calculation). (For noncogeneration case: boiler efficiency, 88 percent; utility power efficiency, 32 percent.)

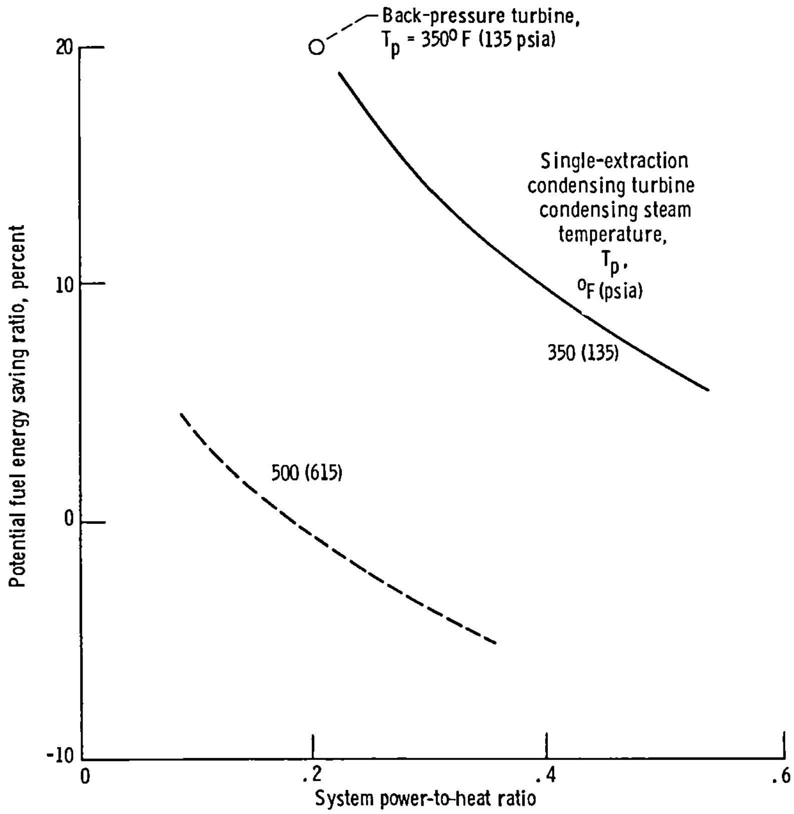


Figure 5.1-4. - Effect of bin approach on power system performance (NASA calculation). (For noncogeneration case: boiler efficiency, 88 percent; utility efficiency, 32 percent.)

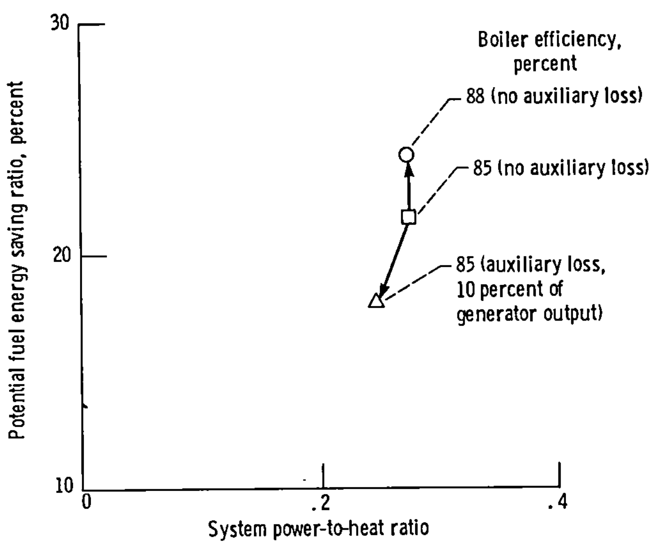
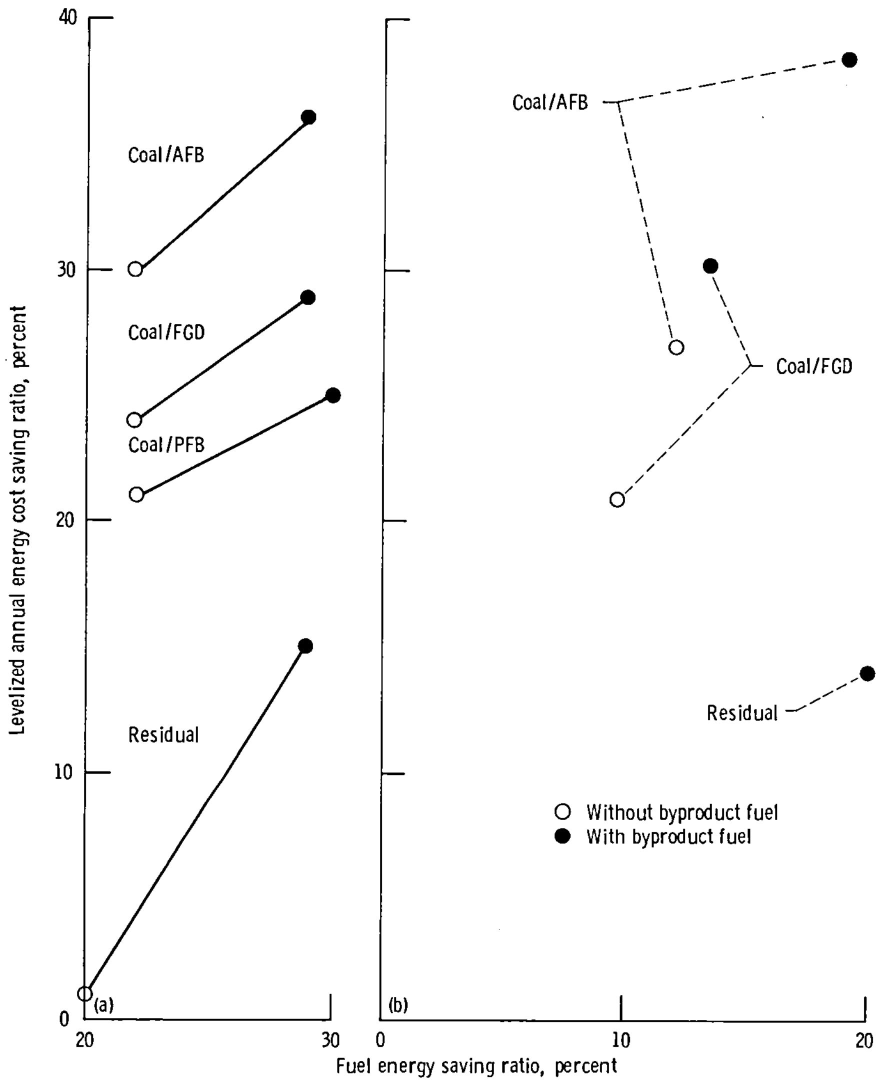


Figure 5.1-5. - Effect of boiler efficiency and auxiliary power requirement on power system performance (NASA calculation). (For noncogeneration case: boiler efficiency, 88 percent; utility efficiency, 32 percent.)



(a) GE steam turbine system/writing paper plant.
(b) UTC steam turbine system/corrugated-paper plant.

Figure 5.1-6. - Effect of byproduct fuel.

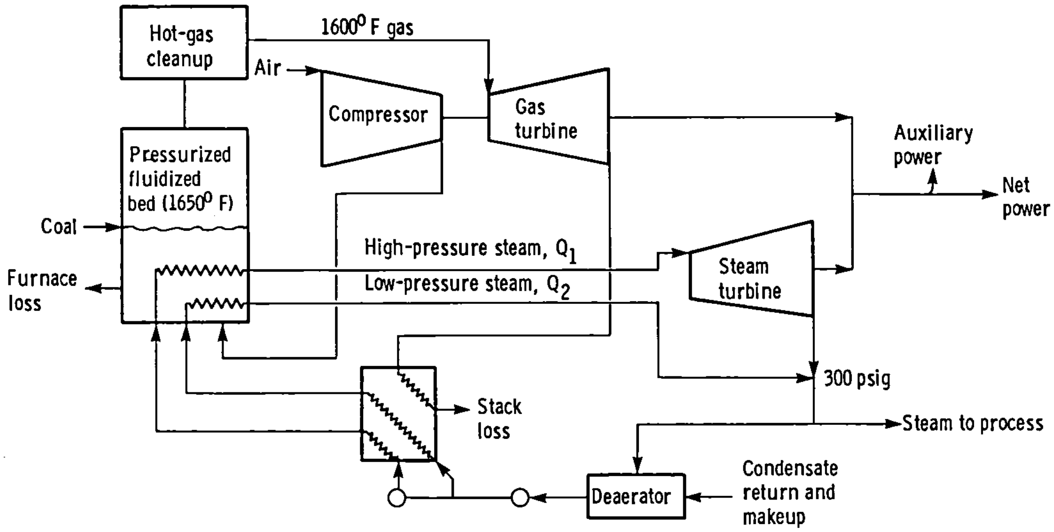


Figure 5.1-7. - NASA supplementary case 2 - steam turbine/PFB.

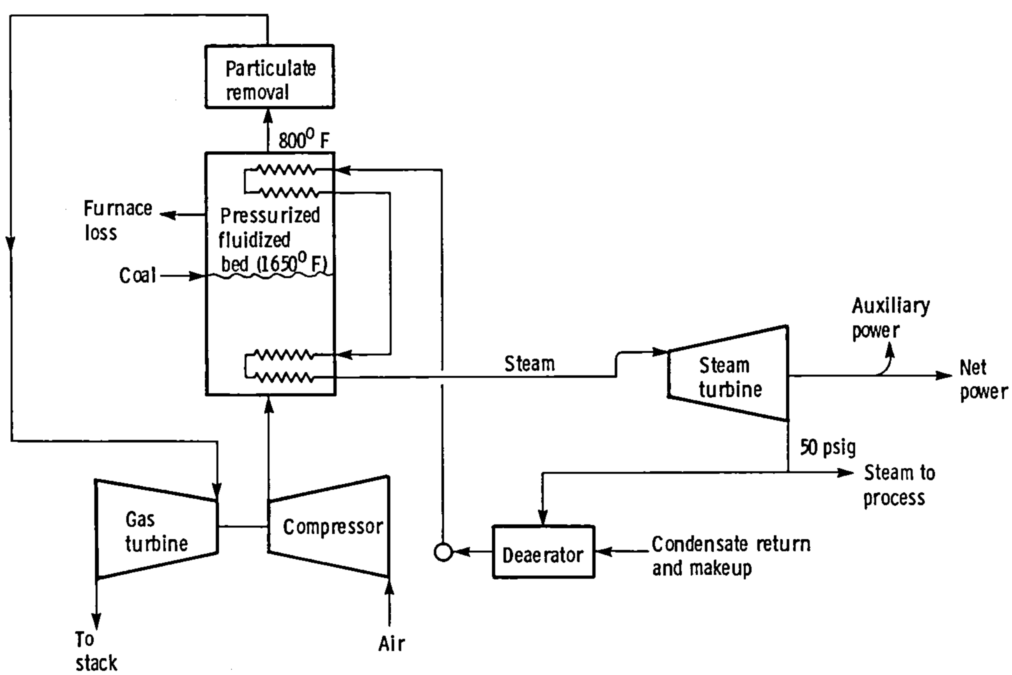


Figure 5.1-8. - NASA supplementary case 3 - steam turbine/PFB.

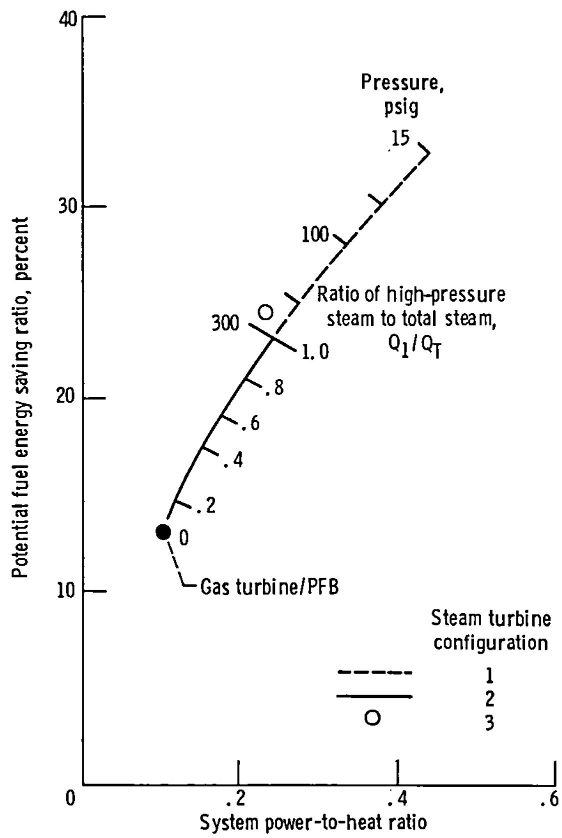


Figure 5.1-9. - Performance characteristics of steam turbine/PFB systems (NASA supplementary cases).

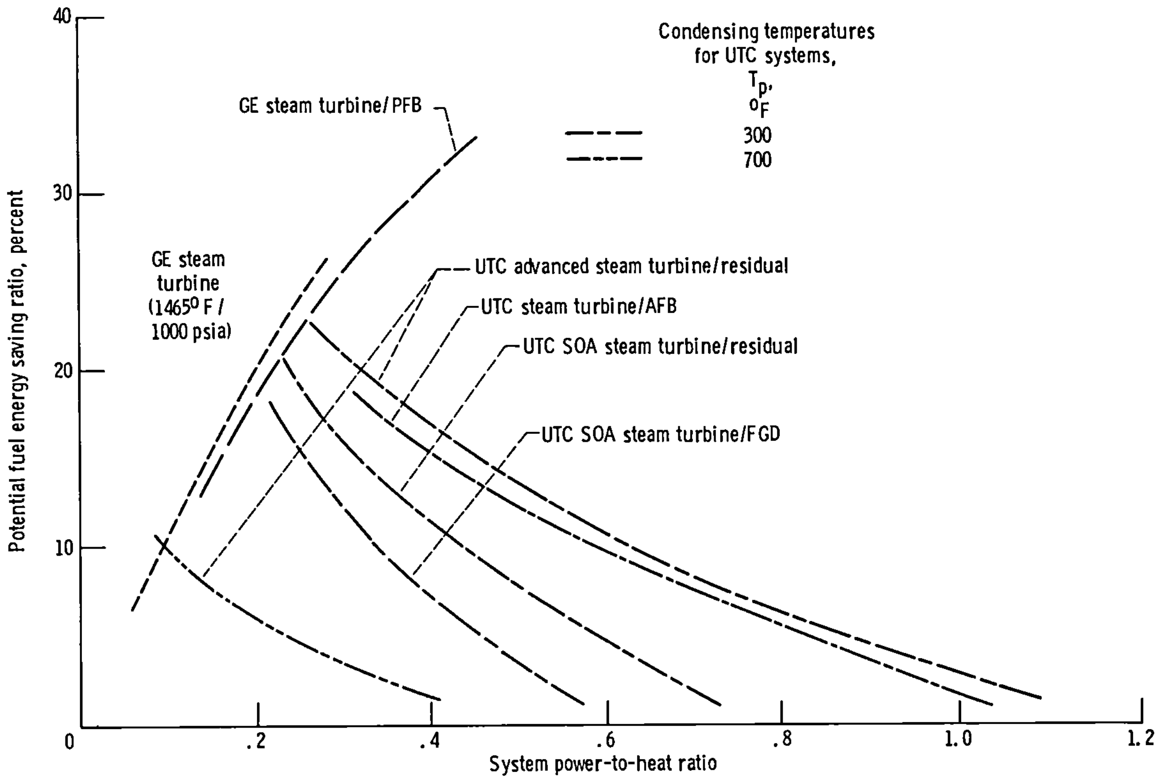


Figure 5.1-10. - Performance characteristics of steam turbine systems (contractors' results). (For noncogeneration case: boiler efficiency, 88 percent; utility efficiency, 32 percent.)

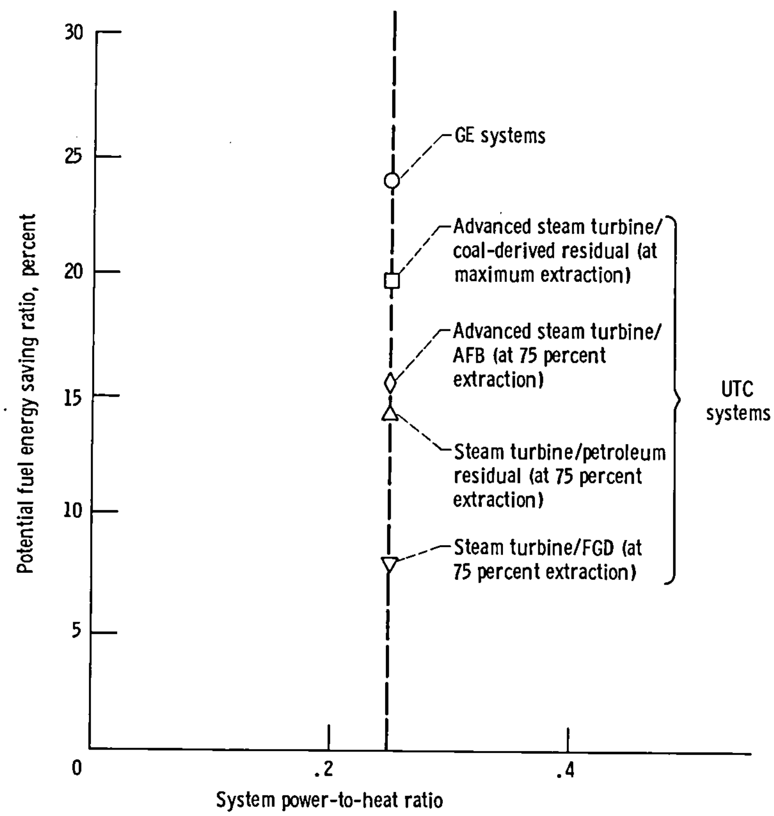
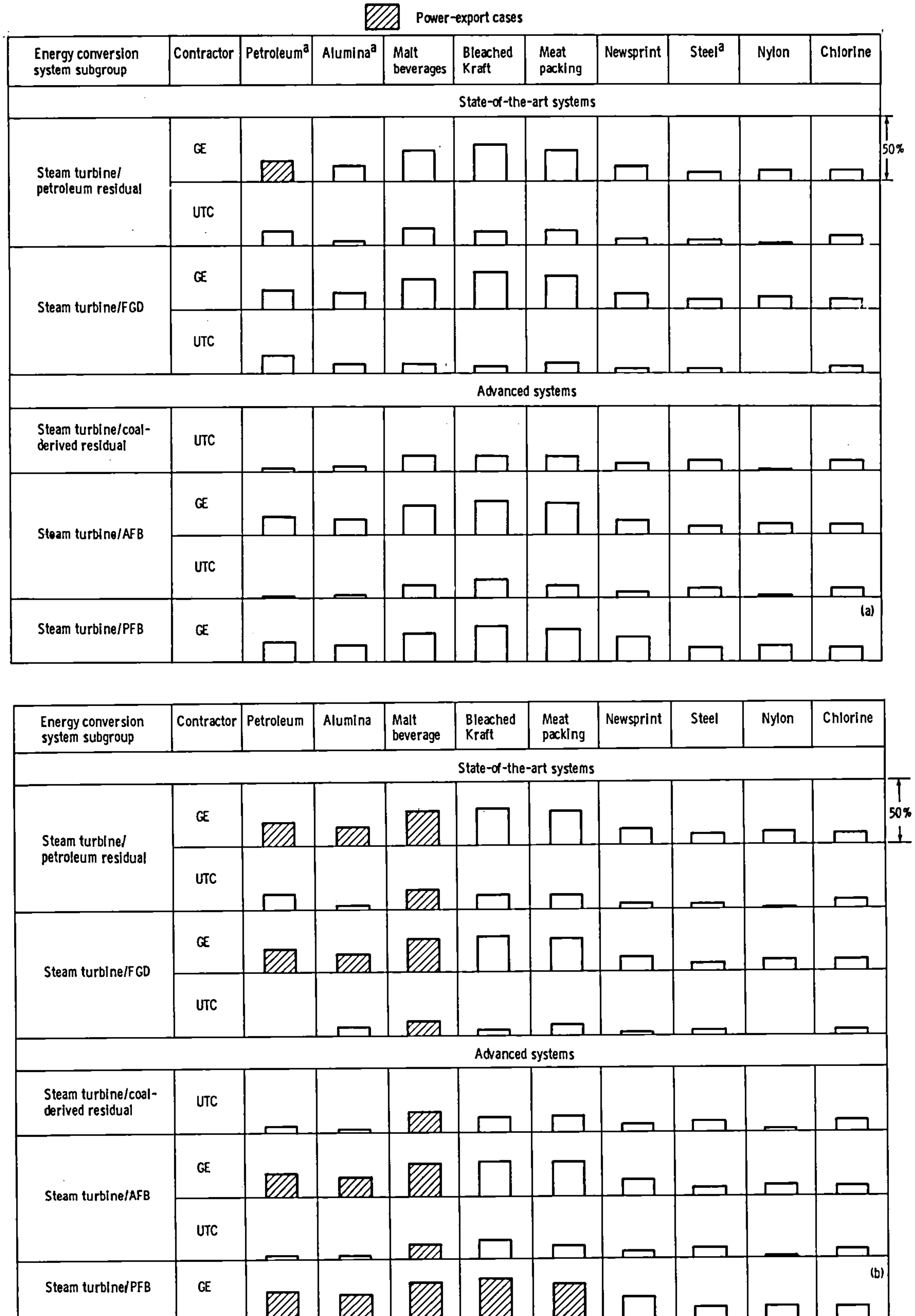


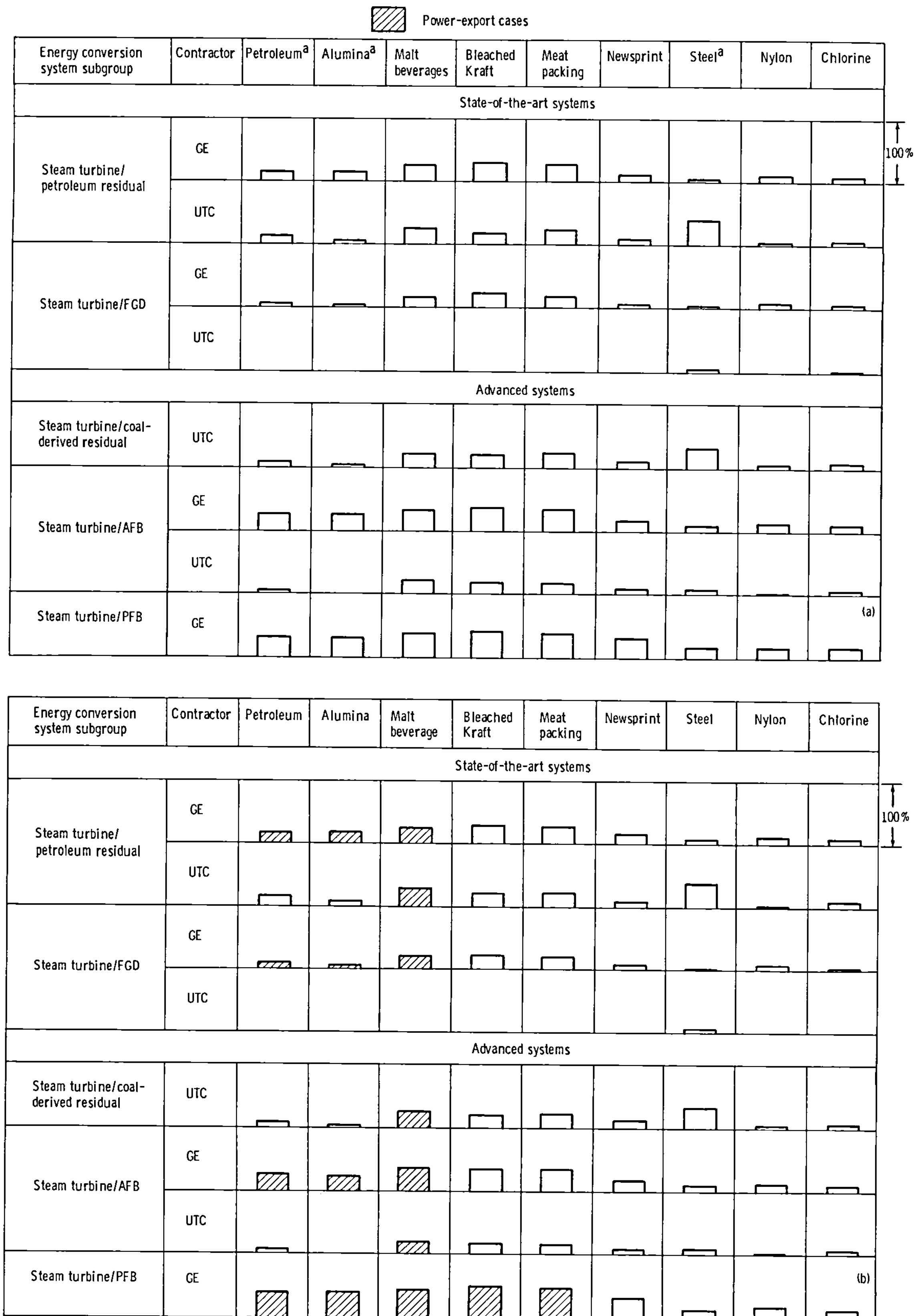
Figure 5.1-11. - Steam turbine performance for a process that requires 30 MW electric, 0.25 power-to-heat ratio, and 300° F steam.



[a] NASA modified UTC results to delete direct-heat requirement.

(a) No power export allowed.
(b) Power export allowed.

Figure 5.1-12. - Fuel energy saving ratio for steam turbine systems. (Blanks denote all negative values.)



[a] NASA modified UTC results to delete direct-heat requirement.

(a) No power export allowed.
(b) Power export allowed.

Figure 5.1-13. - Emissions saving ratio for steam turbine systems. (Blanks denote all negative values.)

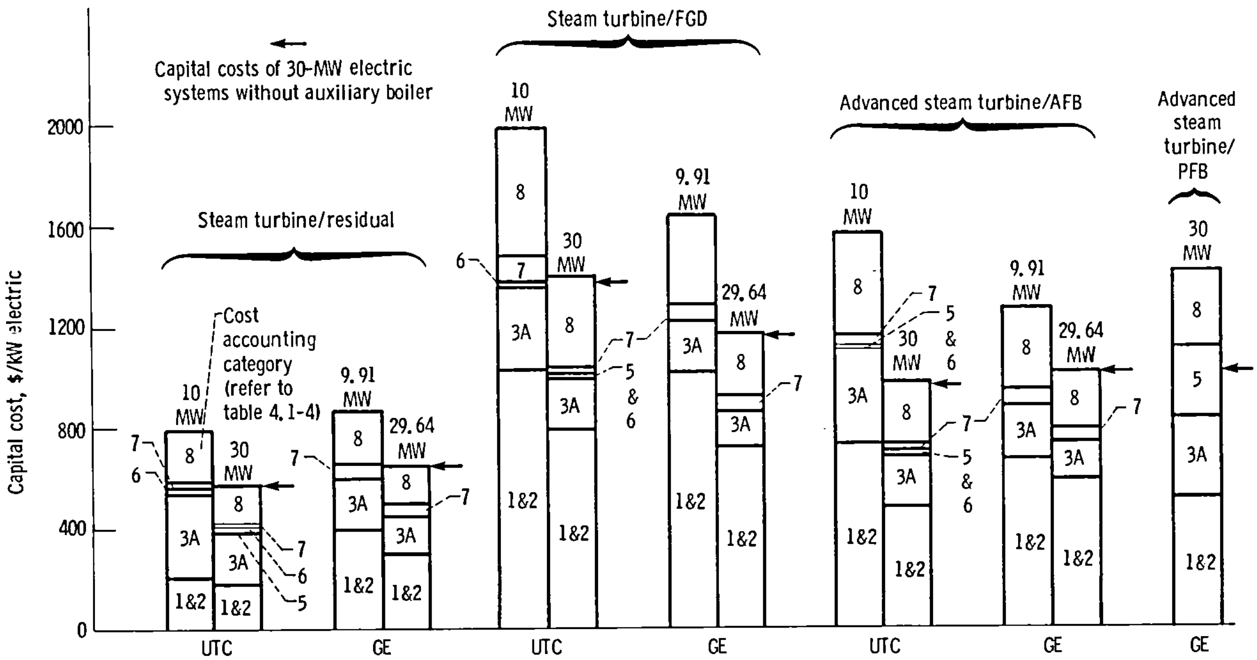


Figure 5.1-14. - Capital costs for steam turbine systems. Electricity generated, 10 and 30 MW; process steam temperature, 300° F.

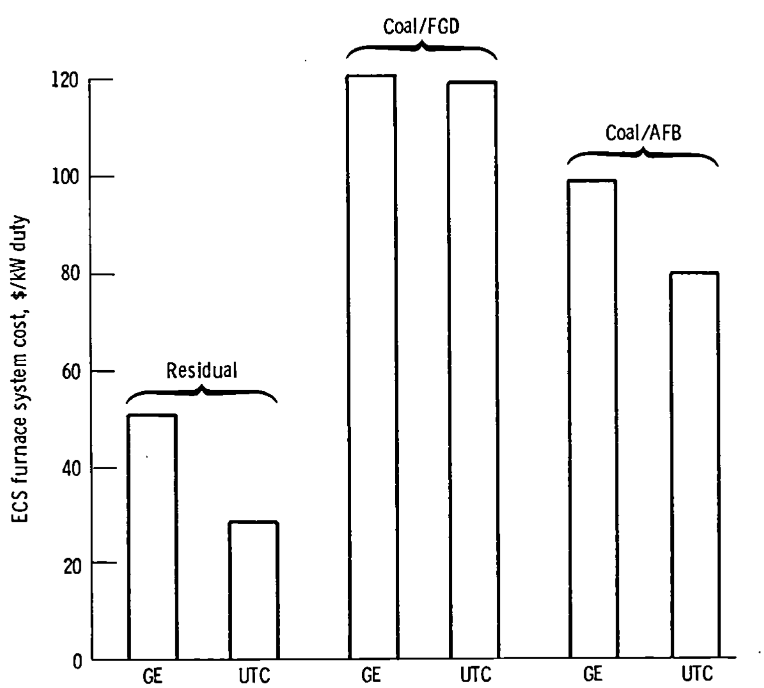
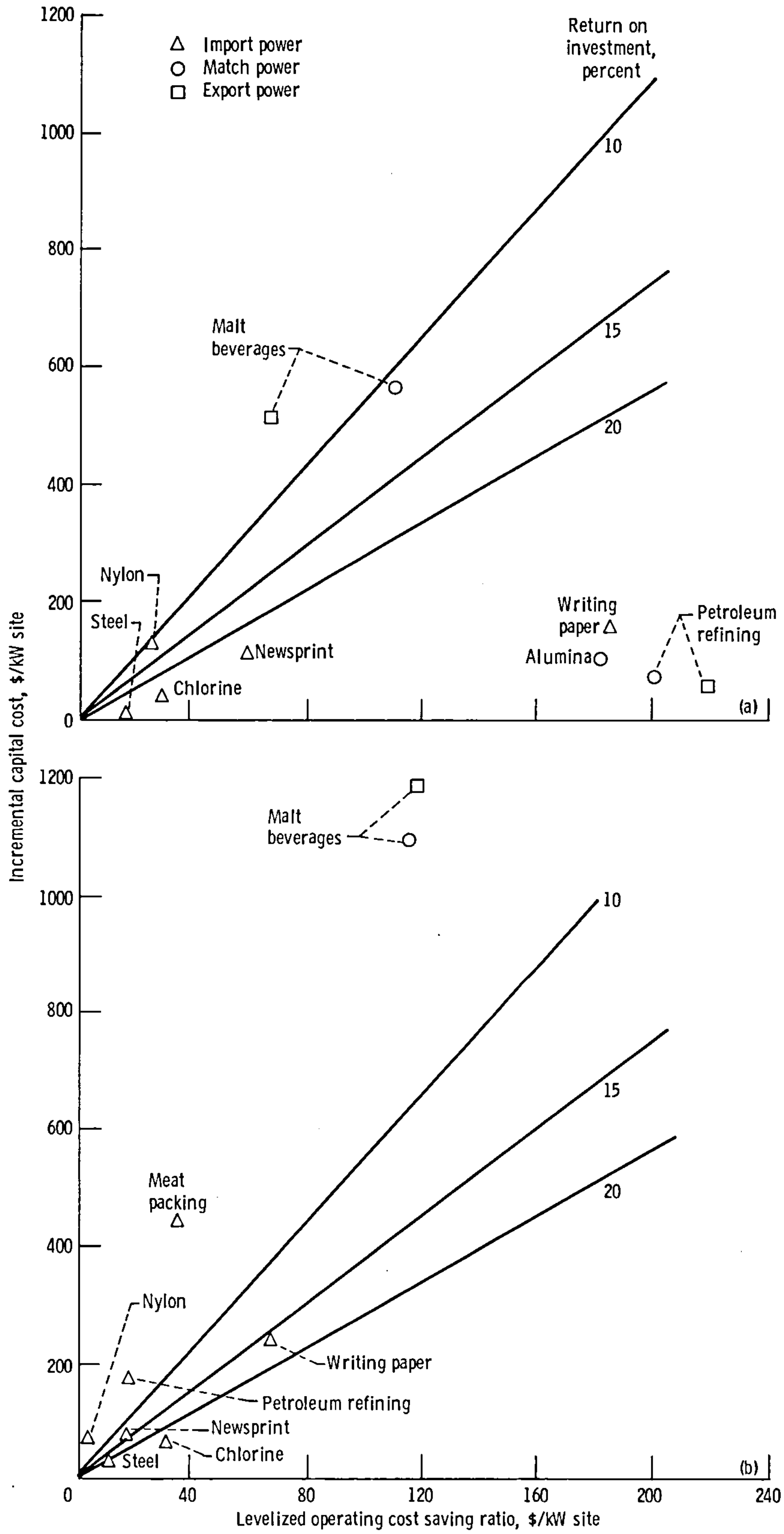
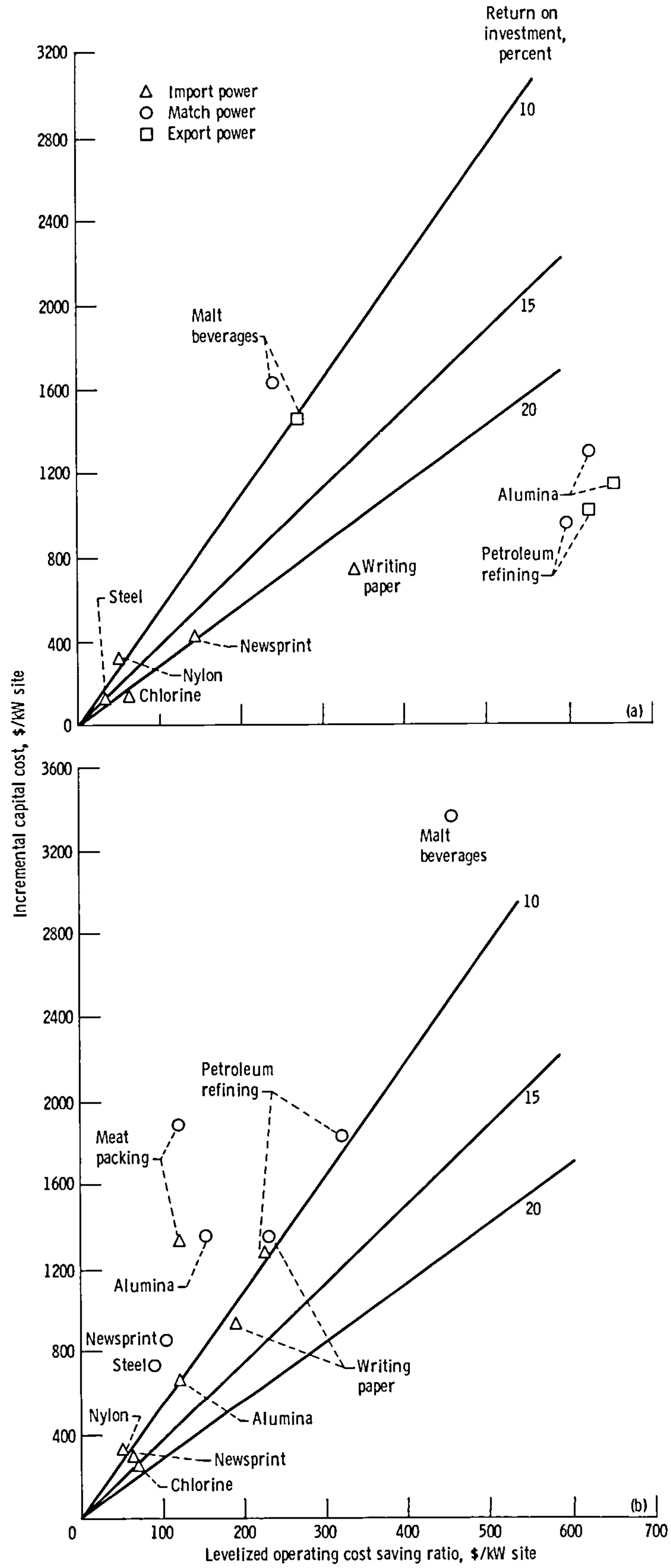


Figure 5.1-15. - Comparison of furnace system costs for steam turbine systems. Electricity generated, 30 MW; process steam temperature, 300° F.



(a) GE.
(b) UTC.

Figure 5.1-16. - Levelized operating cost saving for state-of-the-art steam turbine/residual systems.



(a) GE.
(b) UTC.

Figure 5.1-17. - Incremental capital cost as a function of levelized operating cost saving for state-of-the-art steam turbine/FGD systems.

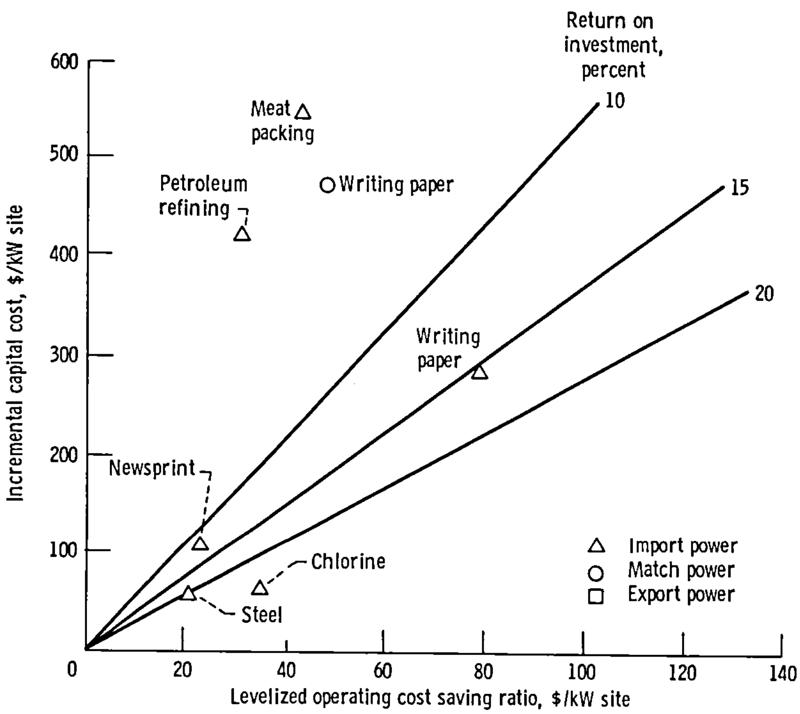
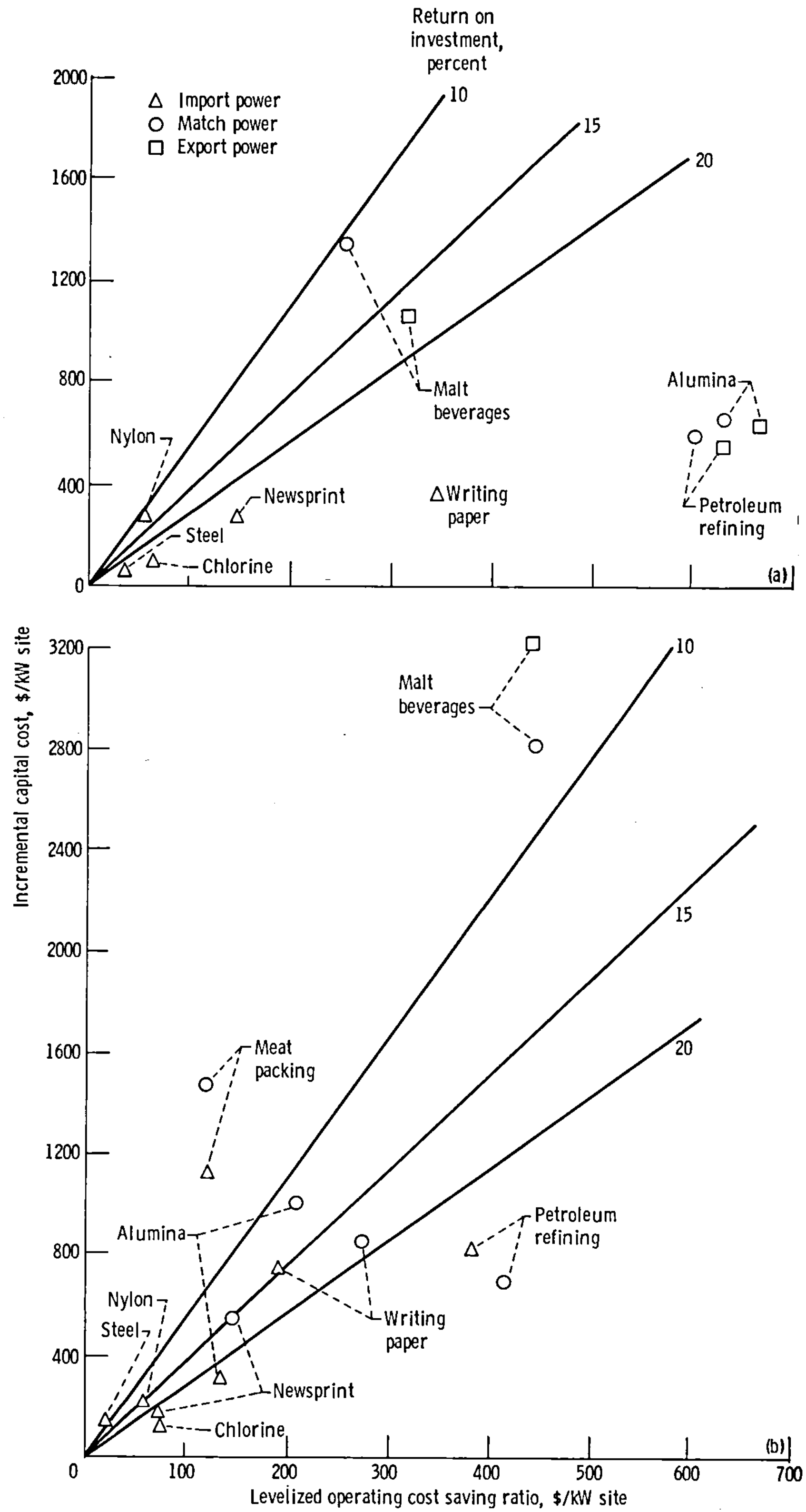


Figure 5.1-18. - Incremental capital cost as a function of levelized operating cost saving for UTC's steam turbine/coal-derived residual system.



(a) GE.
(b) UTC.

Figure 5.1-19. - Incremental capital cost as a function of levelized operating cost saving for steam turbine/AFB systems.

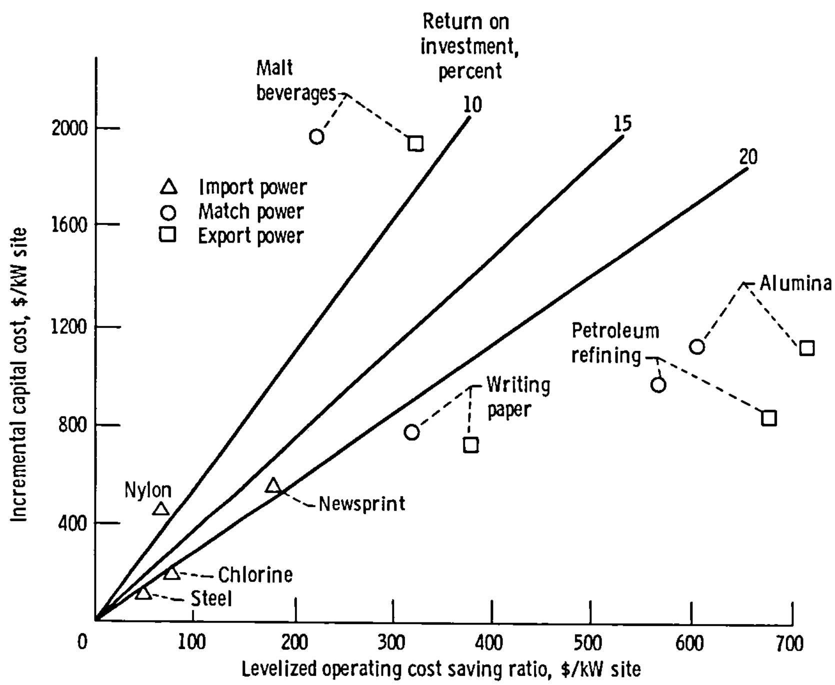
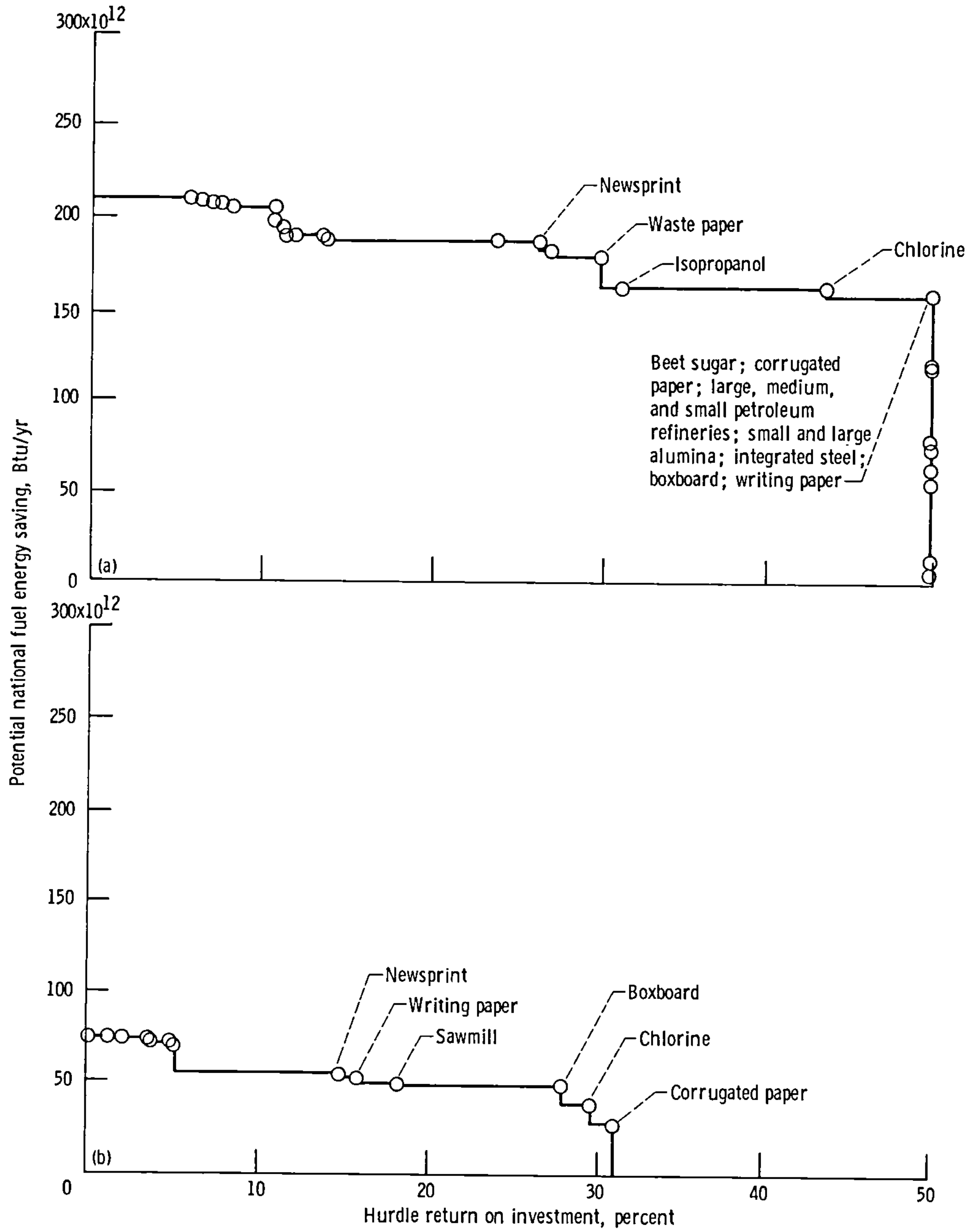


Figure 5.1-20. - Incremental capital cost as a function of levelized operating cost saving for GE's steam turbine/PFB system.

[a] NASA modified UTC results to delete direct heat requirement.

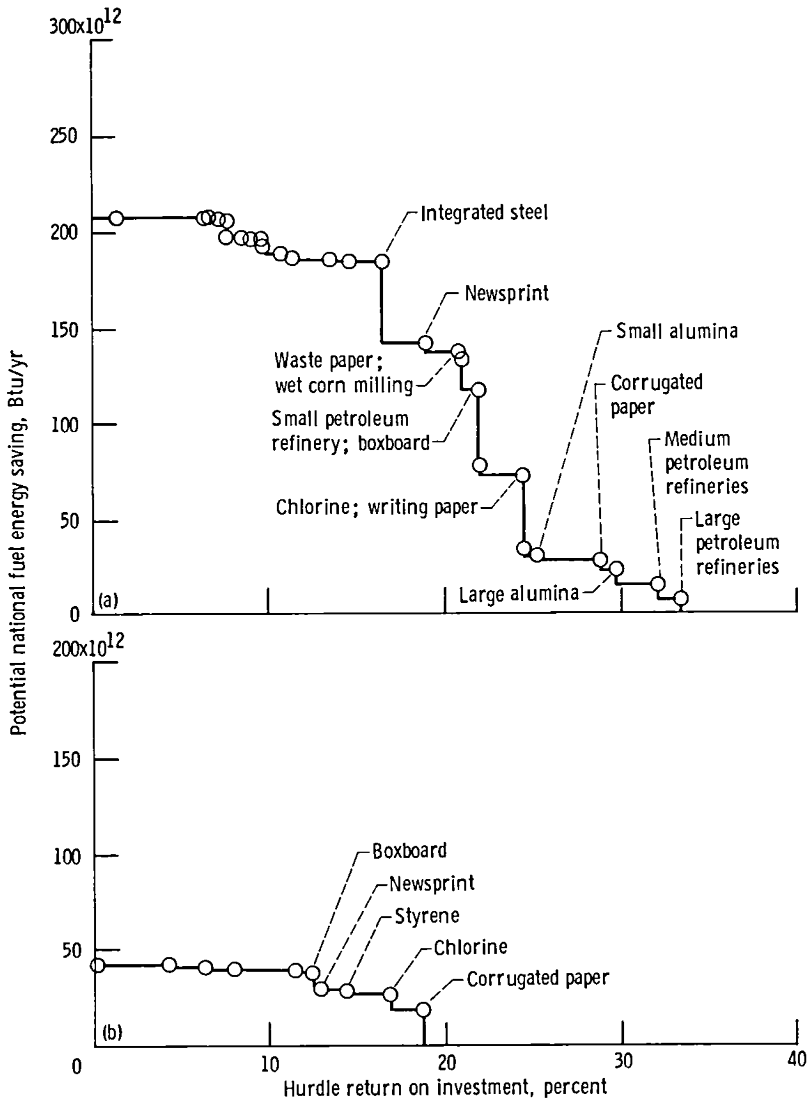
(a) No power export allowed.
(b) Power export allowed.

Figure 5.1-21. - Levelized annual energy cost saving ratio for steam turbine systems. (Blanks denote all negative values.)



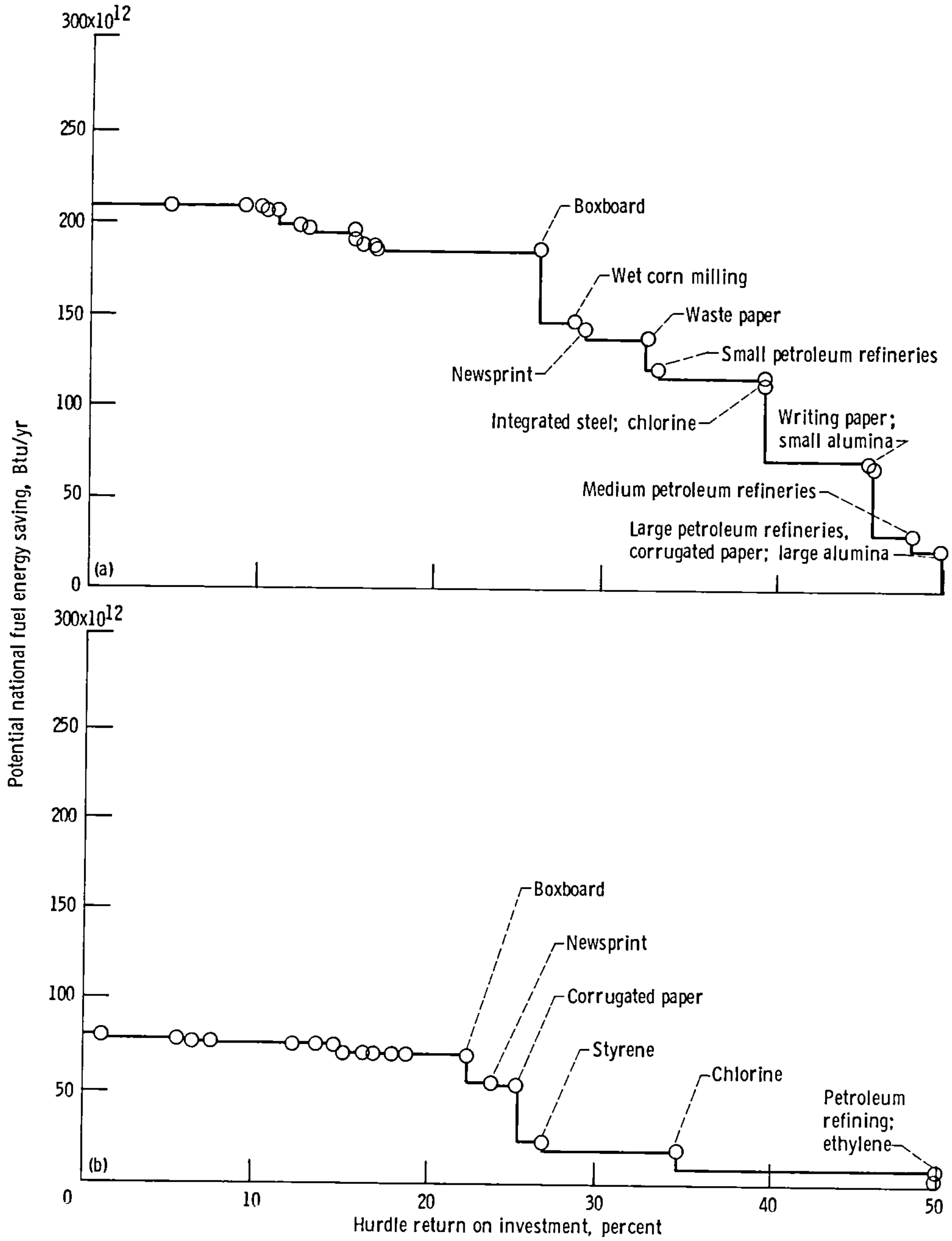
(a) GE.
(b) UTC.

Figure 5.1-22. - Potential national fuel energy saving as a function of hurdle return on investment for state-of-the-art steam turbine/residual systems. (No power export allowed.)



(a) GE.
(b) UTC.

Figure 5.1-23. - Potential national fuel energy saving as a function of hurdle return on investment for state-of-the-art steam turbine/FGD systems. (No power export allowed.)



(a) GE.
(b) UTC.

Figure 5.1-24. - Potential national fuel energy saving as a function of hurdle return on investment for steam turbine/AFB systems. (No power export allowed.)

5.2 DIESEL ENGINE SYSTEMS

Joseph J. Nainiger

5.2.1 Configurations and Parameters

The diesel parameters and configurations considered by each contractor are summarized in table 5.2-1. General Electric selected medium-speed state-of-the-art and advanced diesels operating at 450 rpm. The advanced diesel engine has a higher brake mean effective pressure, resulting in a 1-point increase in efficiency over the state-of-the-art diesel. The advanced diesel also has a higher water/jacket coolant temperature, thereby increasing the possibility of recovering more heat for process use. United Technologies considered both state-of-the-art and advanced low-speed diesels operating at 120 rpm and high-speed diesels operating at 1800 rpm. The advanced low-speed diesel has a higher efficiency and higher water-jacket coolant temperature than its state-of-the-art counterpart. The advanced high-speed diesel has ceramic parts, thus eliminating the need for jacket cooling water, raising the efficiency of the engine, and making available higher temperature rejected heat for process use. This diesel is commonly called adiabatic.

A schematic for the diesel system studied by GE is shown in figure 5.2-1(a). Rejected heat from the turbocharger turbine is recovered with a heat-recovery heat exchanger. Heat is recovered from the jacket cooling water with an ebullient cooling system, where water circulated within the diesel is flashed to steam, which is then used by the process. Heat from the lubricating oil cooler and aftercooler is not recovered since this heat is at a lower temperature than most processes require. In many processes the temperature of the required process steam may be higher than that produced from the water-jacket coolant. In these cases an open-cycle heat pump can be used with the diesel engine, as shown in figure 5.2-1(b). In this arrangement steam from the ebullient cooling system is compressed to the higher pressure and temperature required by the process by a motor-driven compressor. The electricity required to operate the heat pump is taken from the electrical output of the diesel. Thus the diesel heat pump combination is less electrically efficient, but more rejected heat is recovered from the diesel at higher temperatures than would be possible without the heat pump. In many cases this results in higher fuel energy savings.

The schematic shown in figure 5.2-1(c) represents the low-speed diesel configuration studied by UTC. Hot water for process use is heated in heat exchangers that recover heat from the jacket cooling water, the lubricating oil cooler, and the aftercooler. Process steam is raised by using an intermediate, closed steam loop. Boiler feedwater is heated in the aftercooler and is raised to steam by recovering the exhaust gas heat in a heat-recovery heat exchanger. This steam is then condensed while steam is raised for process use in a separate heat exchanger.

The schematic for the UTC high-speed diesel is shown in figure 5.2-1(d). Jacket-water heat is recovered to heat water for process use, and the exhaust heat from the turbocharger is recovered to raise steam. For the advanced adiabatic diesel, water-jacket cooling is eliminated, and the only heat source for process heat is the turbocharger exhaust.

5.2.2 <u>Cogeneration System Performance</u>

5.2.2.1 Fuel Energy Saving Ratio

The ratio of power to process heat produced for a range of process steam (or hot water) conditions is shown in figures 5.2-2 and 5.2-3, together with the cogeneration fuel energy saving that would be achieved if this power-to-heat ratio matched the process needs. As discussed in appendix D, if the site-required power-to-heat ratio differs from the ratio provided by the energy conversion systems as shown in these figures, the fuel saving in most cases would be lower than that shown. Only if the process requires a power-to-heat ratio lower than that produced by the system and a match-heat - export-power strategy is used, will the fuel energy saving ratio equal the value shown in this figure. The open circles represent cogeneration performance if the process requirement is assumed to be only hot water. The state-of-the-art systems are shown in figure 5.2-2 and the advanced diesel systems are shown in figure 5.2-3.

Two design options for UTC's state-of-the-art high-speed diesel are shown in figure 5.2-2. Design option 1 represents high-speed diesels smaller than 1 MW electric, and design option 2 represents diesels between 1 and 15 MW electric. The larger diesels have a higher electrical efficiency, and a larger proportion of their waste heat is recovered for process use, resulting in higher potential FESR. The UTC low-speed diesel has higher electrical efficiency than the high-speed diesel, resulting in slightly higher values of power-to-heat ratio and potential FESR. The results for the GE state-of-the-art medium-speed diesel are between those for the UTC high- and low-speed diesels. Also, note the reduction in the power-to-heat ratio and the increase in potential FESR when the process requires only hot water. This increase in cogeneration performance reflects the greater recovery of low-temperature waste heat from the diesel. This heat is not recovered when steam is the process heat requirement. The primary source of this low-temperature heat is the water-jacket cooling loop.

The potential FESR versus power-to-heat ratio for the advanced diesel systems is shown in figure 5.2-3. The UTC advanced high-speed, adiabatic diesel has the highest potential FESR of any of the systems shown. The projected use of ceramic components in this diesel increases the electrical efficiency of the engine and eliminates the need for water-jacket cooling. Therefore more of the adiabatic diesel's waste heat is at higher temperatures. This results in a higher fraction of heat recovery for process use. The combination of higher electrical efficiency and higher heat recovery results in the high potential FESR. Also shown for UTC are three advanced low-speed cases: two cases use a coal-derived, residual fuel and the third uses pulverized coal as the fuel. These advanced engines have higher electrical efficiencies than the UTC state-of-the-art case shown in figure 5.2-2, and they also have the ability to raise 500° F steam, which was not possible for the state-of-the-art system. However, as shown in figure 5.2-3, the cases where 500° F steam is raised have very high power-to-heat ratios, whereas most of the industrial processes considered have much lower power-to-heat ratios. These cases would exhibit much lower FESR than shown when matched to the industrial processes by using a match-power strategy (appendix D). Note the increase in potential FESR and the decrease in system power-to-heat ratio for these cases when raising 300° F process steam or hot water.

Two GE advanced medium-speed diesel cases are shown in figure 5.2-3 at various process steam temperatures. One case consists of an advanced version of the state-of-the-art case shown in figure 5.2-2. The other case consists of the same advanced diesel with a heat pump, which allows the recovery of jacket cooling water heat at higher temperatures for process use (fig. 5.2-1(b)). The lower electrical efficiency and higher heat recovery of the heat pump case result in lower system power-to-heat ratio but higher potential FESR than the case without the heat pump.

Generally, as shown in figures 5.2-2 and 5.2-3, the diesel systems have relatively high power-to-heat ratios. The potential FESR improves substantially when hot water is a process heat requirement. Both of these characteristics are important in determining the cogeneration performance of the diesel systems when matched to the various processes, as shown later.

Fuel energy saving ratio results of diesel systems matched to nine representative industries are shown in figure 5.2-4. The characteristics of these processes are listed in section 3.2. The processes are listed in figure 5.2-4 in ascending order of power-to-heat ratio. Only matching strategies that produce no export of power are included in figure 5.2-4(a). All matching strategies are considered in figure 5.2-4(b); the one that yields the highest FESR was used for this figure. When export is excluded, the fuel savings shown are generally most attractive for those processes that require a power-to-heat ratio near that produced by the energy conversion system. For the GE state-of-the-art and advanced diesel systems (without heat pump) this corresponds to the processes in the columns to the right since these configurations yield relatively higher power-to-heat ratios (figs. 5.2-2 and 5.2-3). For the GE advanced diesel system with heat pump the maximum FESR occurs in the processes in the middle columns since this configuration yields power-to-heat ratios of 0.6 to 0.8 (fig. 5.2-3). For the UTC systems high FESR is also generally achieved for those processes to the right because of high power-to-heat ratios. In addition, high FESR's are achieved with the meat packing and newsprint processes, since these processes require part of their process heat in the form of hot water, and, as shown in figures 5.2-2 and 5.2-3, the potential FESR improves substantially when hot water is the desired form of process heat.

The FESR results obtained for these nine processes when export of power is allowed are shown in figure 5.2-4(b). The FESR results are improved over those in part (a) in many cases where using a larger power system and making excess power results in a greater amount of heat recovery for process use. The cases that involve export are shaded; the others correspond to match-power or import situations and are the same as in part (a). The lower the site-required power-to-heat ratio as compared with that produced by the system, the greater the amount of excess power produced in a match-heat strategy. This affects the economic results as illustrated in later figures and parametrically in appendix D.

Note that in figure 5.2-4(b) the processes yielding the highest FESR's are meat packing and malt beverages for the GE cases and meat packing for UTC. These are the cases that require some hot water for process use in addition to steam and therefore result in the most heat recovery from the diesel engine systems. The significant improvement in cogeneration performance potential for the diesel engine when heat is recovered as hot water is indicated in figures 5.2-2 and 5.2-3.

5.2.2.2 Emissions Saving Ratio

The emissions saving ratio is shown for the diesel systems matched to the nine representative industrial processes in figure 5.2-5. The emissions saving ratio, defined in section 2.5, is the percentage reduction in emissions when both the utility site and the industrial site are considered. The results shown in figure 5.2-5 correspond to the total of NO_x, SO_x, and particulate emissions and are calculated by assuming the use of a coal-derived residual fuel in the noncogeneration onsite boiler. For the UTC cases coal was assumed to be used at the utility. For the GE cases a fuel mix consisting of 77 percent coal and 23 percent coal-derived residual fuel was assumed to be used by the utility. In addition to the amount of fuel saved, the emission savings depend strongly on the combustion characteristics of the energy conversion system and the type of fuel used. The emissions per unit of fuel consumed are shown in table 5.2-2 for each contractor's systems.

As shown in figure 5.2-5, with the exception of UTC's advanced high-speed diesel and a few cases with GE's advanced medium-speed diesels, no emissions savings are achieved with the diesel engine. This is due to the high NO_x emissions estimated by both contractors for their respective diesel systems (table 5.2-2). Although the NO_x emissions estimates for the advanced diesel systems are generally lower than those for the state-of-the-art systems, none of the diesel systems (either state of the art or advanced) would meet proposed environmental restrictions on NO_x emissions. UTC's advanced high-speed diesel did achieve an emissions saving inspite of high NO_x emissions because of its high fuel energy saving (fig. 5.2-4). The high NO_x emissions for the diesel systems may be a serious deterrent to marketing the diesel engine as a cogeneration system. Further research into this area is needed.

5.2.2.3 Capital Cost

A capital cost comparison between the contractors' diesel systems is shown in figures 5.2-6 and 5.2-7. Capital costs in dollars per kilowatt of electricity produced by the system are shown for a 10-MW-electric system with recovery of heat as 300° F steam. The state-of-the-art systems are shown in figure 5.2-6 and the advanced systems are shown in figure 5.2-7. Each contractor estimated the costs according to the cost accounts described in section 4.1. The bar graphs include all costs of equipment and installation for a 10-MW-electric system including all fuel-handling, storage, and processing equipment, and all heat recovery equipment. Because each cogeneration system produces a different power-to-heat ratio and thus would need a different size and cost supplementary boiler when matched to a common process, bar graphs are also shown that include a supplementary boiler large enough to yield a power-to-heat ratio of 0.25. As indicated by figure 3.2-2 this power-to-heat ratio is near the mean value for all of the processes studied in CTAS.

A capital cost comparison between the state-of-the-art diesels is shown in figure 5.2-6. The low- and medium-speed diesels studied by UTC and GE, respectively, are shown to be nearly twice as costly as UTC's high-speed diesel. Without considering the supplementary boiler cost the capital costs for the UTC low-speed and GE medium-speed diesel systems are in close agreement. The engine cost (category 3) of the UTC low-speed diesel is somewhat higher than that of GE's medium-speed diesel, but the balance-of-plant capital cost (category 7) is higher for the GE case, thus resulting in similar overall

capital costs without the supplementary boiler cost included. However, the capital costs for the supplementary boiler (category 5) are quite different for the two systems, with GE's cost estimate approximately five times that of UTC's, even though the thermal duties of the boilers are approximately the same. Differences in cost category 8 (contingency and A&E services) are due to two factors. First, since these adders are a certain percentage of the total accumulative costs of the other cost categories, the category 8 costs will reflect differences in these accumulated costs. Second, as mentioned in section 4.2, different percentages were used by the contractors for contingency and A&E services.

A capital cost comparison for the contractors' advanced diesel systems is shown in figure 5.2-7. The capital cost estimate for UTC's low-speed diesel burning coal is higher that for than UTC's low-speed diesel burning coal-derived residual fuel because of the higher capital cost estimate for coal and waste handling (category 1). As mentioned previously for the state-of-the-art capital cost comparison, the UTC capital cost estimate for the advanced low-speed diesel engine itself (category 3) is higher, whereas the GE estimate for the balance of plant (category 7) is higher. Also, as in the state-of-the-art cases there is a substantial difference between the contractors in the capital cost estimate for the supplementary boiler. Without the supplementary boiler cost included, the UTC captial cost for its low-speed diesel system is slightly higher than the GE capital cost for its medium-speed diesel. When the supplementary boiler cost is considered, the GE system has a slightly higher overall estimate. Note that the capital costs for the advanced UTC high-speed diesel and the GE medium-speed diesel are slightly lower than the capital costs for their respective state-of-the-art configurations. The capital cost for the advanced UTC low-speed diesel burning residual fuel is slightly higher than that of its state-of-the-art counterpart.

5.2.2.4 Economics

The levelized annual operating cost saving versus incremental capital cost is shown in figures 5.2-8 to 5.2-11 for both contractors' diesel systems matched with the nine representative industrial processes. Levelized annual operating cost saving is defined as the difference in levelized annual operating costs for fuel, electricity, and operations and maintenance (O&M) between the cogeneration system and the noncogeneration case. In each figure the origin corresponds to the noncogeneration situation, where all required power is purchased and onsite steam is produced in a residual-fueled boiler. Since the power requirement varies considerably from process to process (table 4.4-1), the incremental capital cost and the levelized operating cost saving are expressed per unit of site power required. As noted, not all of the cogeneration cases are sized to match the site power requirement. Also shown are lines of constant return on investment.

The incremental capital cost versus levelized annual operating cost saving is shown in figures 5.2-8 and 5.2-9 for the state-of-the-art diesel systems of GE and UTC, respectively. As shown, none of the state-of-the-art cases achieves an ROI of 10 percent or greater. The incremental capital costs are larger for the export-power cases than for the corresponding match-power cases since the onsite energy conversion system is larger. But the operating saving in none of these cases is raised sufficiently in comparison to the capital cost increase to make the ROI's for export-power cases higher than those for corresponding match-power cases.

The results for the GE advanced diesel systems are shown in figure 5.2-10. The advanced medium-speed diesel cases shown in figure 5.2-10(a) have slightly lower incremental capital costs and slightly higher levelized annual operating cost savings than the state-of-the-art systems shown in figure 5.2-8. The ROI's for these advanced cases are less than 10 percent. In figure 5.2-10(b) results are shown for GE's advanced medium-speed diesel with heat pump. Here, three cases achieve ROI's between 10 and 15 percent. Two of these cases are import-power situations, where the diesel system supplies only part of the process electrical requirement. The combination of good levelized annual operating cost saving and lower incremental capital cost (by sizing the powerplant smaller) results in higher values of ROI.

The incremental capital cost versus levelized annual operating cost saving for the UTC advanced diesel systems is shown in figure 5.2-11. The results for the advanced low-speed diesel burning coal-derived residual fuel (fig. 5.2-11(a)) show no ROI's of 10 percent or higher. However, several low-speed diesels burning coal achieve ROI's between 10 and 15 percent (fig. 5.2-11(b)). Although the coal-fired cases generally have slightly higher incremental capital costs than the liquid-fueled cases the use of less expensive coal as a fuel substantially increases the levelized annual operating cost saving and thus results in a higher range of ROI for the coal-fired cases. In figure 5.2-11(c) results are shown for UTC's advanced high-speed diesel. Although this configuration uses relatively expensive coal-derived distillate fuel, two cases do manage to achieve ROI's greater than 10 percent. The higher range of ROI's is achieved in spite of the higher fuel cost because of the large fuel energy saving achieved with this diesel system.

The other economic parameter used in CTAS to combine the effects of capital and operating cost is the percent saving in levelized annual energy cost, defined in section 2.5. In figure 5.2-12 the levelized annual energy cost saving ratio (LAECSR) is shown for the cogeneration diesel systems matched to the nine representative industrial processes. In part (a) only cases that do not involve export are included; in part (b) all cases are included. In each part of the figure, when there is more than one matching strategy to choose from, the one with highest LAECSR is shown.

The state-of-the-art diesel systems show little or no LAEC savings. Of the advanced systems the UTC coal-fired, low-speed diesels have the highest LAECSR values because of the lower price for coal. Of the GE advanced systems the cases with heat pumps have higher LAECSR's than those without heat pumps.

LAECSR's are shown for cases including export of electricity in figure 5.2-12(b). With only a few exceptions the results are the same as in part (a) for both contractors. The cases including export have lower LAECSR's than those without. By including export, excess electricity is generated and sold to a utility at 60 percent of the price at which the industry buys electricity from the utility. However, the increased capital cost component of the levelized annual operating cost and the increased cost of fuel more than offset the revenue from the sale of electricity. The export cases would look more attractive economically with a higher sell-back price of electricity.

The results in figures 5.2-8 to 5.2-11 generally agree with those in figure 5.2-12 concerning which processes yield the most attractive results for each type of diesel system. It is consistent that the exclusion of export of electricity and the use of the advanced diesel systems (rather than state-of-the-art systems) yield more attractive economic results.

5.2.2.5 Relative National-Basis Fuel Saving

Fuel savings accumulated to a national basis as a function of hurdle return on investment are shown in figures 5.2-13 to 5.2-16. The procedure used to calculate these curves is described in section 4.4. It was assumed for each system that it would be 100 percent implemented in new-capacity additions or retirement replacements between 1985 and 1990 in each process where the results yield an ROI greater than the hurdle rate shown. Results were calculated for the GE systems by using 40 of the processes they studied and for the UTC systems by using 26 processes. No extrapolation beyond these processes was performed. These figures are intended to illustrate the comparative potential savings versus ROI requirement, not as an illustration of the absolute magnitude of savings.

The results for the state-of-the-art diesel engine are shown in figure 5.2-13. Only cogeneration strategies that do not involve export of power from an individual plant site are included. Note that the results for the UTC low-speed diesel extend to a much higher range of ROI and potential fuel energy saving than the results for UTC's high-speed diesel or GE's medium-speed diesel. The UTC low-speed diesel results show some processes that achieve a higher ROI than shown in figure 5.2-9(a) for the subset of nine processes. For the GE cases and UTC's high-speed diesel cases the range of ROI does not reach 5 percent. For the UTC low-speed diesel only two cases have ROI's of 10 percent or greater.

The results for the state-of-the-art systems when export of power from individual plant sites is allowed are shown in figure 5.2-14. For the GE medium-speed diesel and UTC low-speed diesel the inclusion of export results in lower potential fuel energy savings than shown in figure 5.2-13, which does not include export. In addition, for the UTC low-speed diesel the range of ROI also decreases when export of power is included. The range of ROI and potential national fuel saving increase slightly for the UTC high-speed diesel with the inclusion of export. However, with export no state-of-the-art cases for either contractor achieve a hurdle ROI of greater than 10 percent.

The potential national fuel saving versus hurdle ROI for the GE advanced diesel systems is shown in figure 5.2-15 for no power export. Note the substantial increase in potential national fuel saving and range of ROI for the advanced cases over those for the GE state-of-the-art cases shown in figure 5.2-13. The medium-speed diesel without a heat pump (part (a)) achieves a higher potential national fuel saving than the diesel with a heat pump (part (b)) at low values of hurdle ROI. However, the diesel with a heat pump achieves a high range of hurdle ROI, with several cases between 10 and 15 percent.

The results for the UTC advanced diesel systems are shown in figure 5.2-16. The advanced UTC diesels generally achieve higher potential national fuel savings and ranges of ROI than the UTC state-of-the-art systems shown in figure 5.2-13. The UTC advanced low-speed diesel burning coal achieves the highest range of ROI of any of the advanced systems (GE or UTC). The UTC advanced high-speed diesel achieves higher potential national fuel saving at low hurdle ROI's than either of the UTC advanced low-speed cases. Also no advanced diesel (UTC or GE) achieves a hurdle ROI of 20 percent or greater.

5.2.3 Summary

The range of results achieved by the diesel systems for a subset of processes are shown in table 5.2-3. For each subgroup the industrial process that yields the maximum value is indicated. Generally, the fuel energy saving ratio is good for both contractors, with maximum values ranging from the mid 20's to upper 40's. The GE systems without export result in highest FESR when matched to the nylon process when the diesel does not use a heat pump and when matched to the newsprint process when the diesel does use a heat pump. In both situations these processes require a power-to-heat ratio that closely matches the ratio produced by the respective GE diesel system at the required steam temperature. For UTC the diesel matched with either the meat packing, newsprint, or chlorine processes results in the best FESR. Both meat packing and newsprint require some process heat in the form of hot water. As shown in figures 5.2-2 and 5.2-3 the FESR for the diesel systems improves substantially when hot water is a process requirement. Also, as shown in those figures, the power-to-heat ratios for the UTC systems are relatively high when raising process steam only. Thus the chlorine industry, with its high power-to-heat ratio, most closely matches the system power-to-heat ratios. When export of electricity is allowed, the highest FESR for both contractors is achieved in either the meat packing or malt beverage processes. Again, this is a result of the hot water requirements of these two processes and the ability of the diesel system to deliver low-grade heat to satisfy those requirements.

The emissions saving ratios of the diesel cogeneration systems are generally either nonexistent or relatively low. For most cases the use of a diesel cogeneration system would result in greater environmental emissions than in the noncogeneration case. As mentioned previously, the high emissions are a result of the inherently high NO_x emissions from diesel engines. Even though in some cases a positive EMSR is shown, in no cases will the environmental restriction on NO_x emissions be met. This could seriously inhibit the use of diesel engines in cogeneration applications.

The levelized annual energy cost saving is relatively low for the liquid-fueled diesel systems. However, since the LAEC saving is dominated by the operating cost saving, the values achieved by the UTC coal-fired configuration are much higher because of the lower price of that fuel. There is no increase in LAEC when export of electricity is allowed since the higher capital costs of the system when exporting electricity more than offset the revenue from its sale. A higher sell-back price for the excess power (60 percent of the utility selling price was assumed) would significantly improve the export cases.

For the ROI results shown only three advanced diesel configurations achieve values of ROI greater than 10 percent. Of these the highest range of ROI is achieved with the coal-fired diesel studied by UTC. As in the case of LAEC savings the range of ROI does not increase when export of electricity is allowed primarily because of the higher capital costs and the relatively low sell-back price of electricity.

Although the diesel system cogeneration results indicate good fuel energy savings, the emissions and economic results are relatively less attractive than those for other candidates studied. The diesel has better cogeneration performance when hot water is required by the process. However, the contractors' industrial data indicate relatively few industries where substantial amounts of hot water are required. In some of the processes that need hot water (e.g.,

the food industry) the hours of operation per year are low. The operating cost savings per year are therefore lower than if the processes had been at higher load factors. Thus the economic results are not attractive.

TABLE 5.2-1. - ENERGY CONVERSION SYSTEM PARAMETERS AND CONFIGURATIONS STUDIED FOR DIESEL SYSTEMS

Parameter	General Electric Co.	United Technologies Corp.
Low speed:		
Jacket coolant temperature, °F	--------------	158
Size range, MW	--------------	8 to 29
Speed, rpm	--------------	120
Fuel		Petroleum residual
Medium speed:		
Jacket coolant temperature, °F	175	------------------
Size range, MW	0.3 to 10	------------------
Speed, rpm	450	------------------
Fuel	Distillate and residual	------------------
High speed:		
Jacket coolant temperature, °F	--------------	200
Size range, MW	--------------	0.2 to 15
Speed, rpm	--------------	1800
Fuel	--------------	Petroleum residual
Low speed:		
Jacket coolant temperature, °F	--------------	266
Size range, MW	--------------	8 to 29
Speed, rpm	--------------	120
Fuel		Coal-derived residual and pulverized coal
Medium speed:		
Jacket coolant temperature, °F	250	------------------
Size range, MW	2 to 15	------------------
Speed, rpm	450	------------------
Fuel	Residual	------------------
Heat pump design	Yes	------------------
High speed:		
Jacket coolant temperature, °F	--------------	None (adiabatic)
Size range, MW	--------------	0.4 to 15
Speed, rpm	--------------	1800
Fuel	--------------	Coal-derived distillate

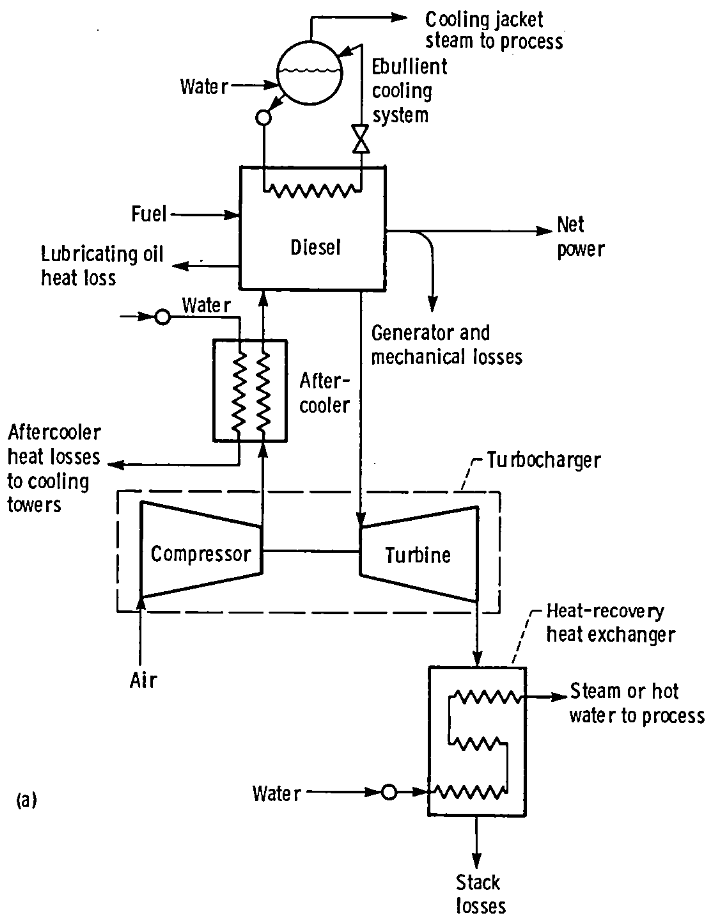
TABLE 5.2-2. - EMISSIONS FOR DIESEL SYSTEMS

Energy conversion system subgroup	Contractor	Fuel	Emissions, lb/10^6 Btu fuel		
			SO_x	NO_x	Particulates
State-of-the-art systems					
Low speed	UTC	Petroleum residual	0.757	3.68	0.012
Medium speed	GE	Petroleum distillate	.52	3.8	0
		Petroleum residual	.75	8.1	.016
High speed	UTC	Petroleum distillate	.516	4.0	.02
Advanced systems					
Low speed	UTC	Coal-derived residual	0.824	3.68	0.012
Medium speed	GE	Coal	1.2	3.5	.10
		Coal-derived residual	.8	1.9	.153
		Coal-derived residual	.8	1.9	.153
High speed	UTC	Coal-derived distillate	.565	2.0	.02

TABLE 5.2-3. - RANGE OF RESULTS FOR DIESEL SYSTEMS USED WITH THE NINE REPRESENTATIVE INDUSTRIES

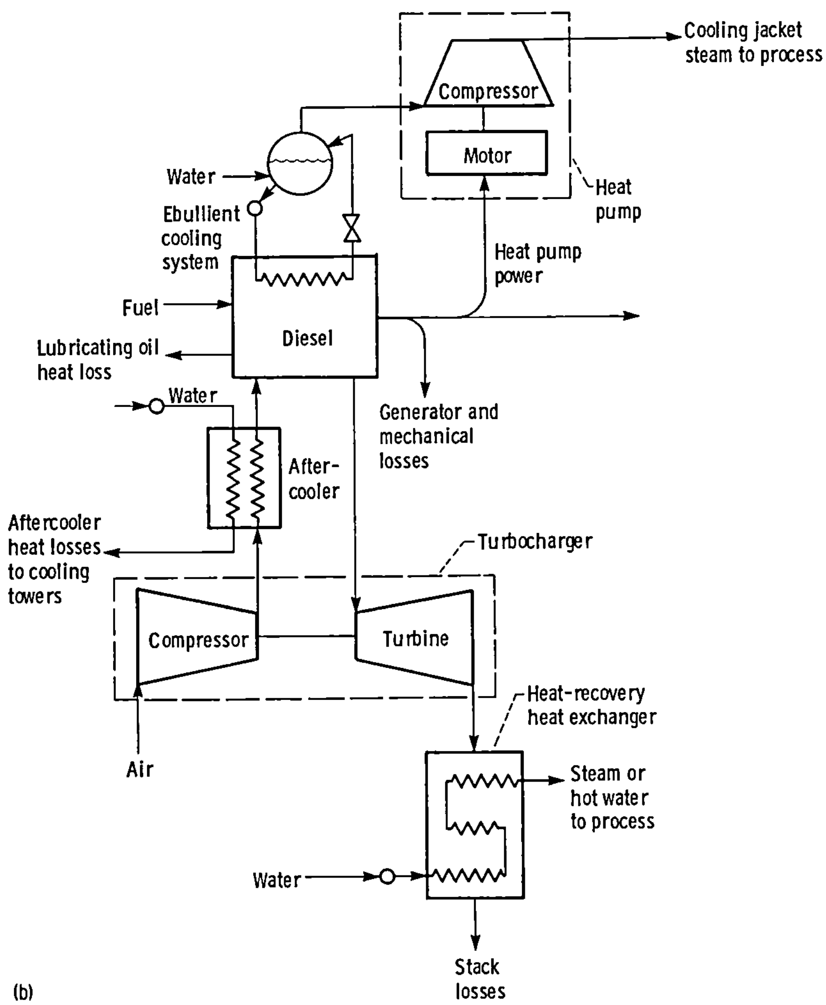
Subgroup	Contractor	Fuel energy saving ratio, FESR, percent	Industry with maximum FESR	Emission saving ratio, EMSR, percent	Industry with maximum EMSR	Levelized annual energy cost, LAEC, percent	Industry with maximum LAEC	Return on investment, ROI, percent	Industry with maximum ROI
State-of-the-art systems									
Low speed	UTC	5.4-25.3	Newsprint	Negative	-------	Negative to 5	Chlorine	0-6.8	Writing paper
Medium speed	GE	14.2-27.0	Nylon	Negative	-------	Negative	--------	0-4	Nylon; chlorine
High speed	UTC	1.0-25.5	Meat packing	Negative	-------	Negative to 0.8	Chlorine	0-7.3	Chlorine
Advanced systems									
Low speed/residual	UTC	5.6-32.0	Newsprint	Negative	--------	Negative to 10 6	Newsprint	0.2-9.0	Writing paper
Low speed/coal	UTC	5.5-26.8	Chlorine	Negative	--------	0.2-31.2	Newsprint	5.5-14.7	Newsprint
Medium speed	GE	16.8-29.2	Nylon	Negative to 12	Writing paper	Negative to 7.9	Chlorine	0-9	Chlorine
Medium speed with heat pump		9.1-31.3	Newsprint	Negative to 16	Writing paper	Negative to 11.3	Newsprint	0-14	Chlorine
High speed	UTC	5.5-47.6	Chlorine	1.9-29.6	Chlorine	Negative to 11.2	Chlorine	0-12.1	Steel
State-of-the-art systems									
Low speed	UTC	5.4-35.7	Meat packing	Negative	-------	Negative to 5	Chlorine	0-6.8	Writing paper
Medium speed	GE	14.2-35.8	Malt beverages	Negative	-------	Negative	--------	0-4	Nylon; chlorine
High speed	UTC	1.0-36.3	Meat packing	Negative	-------	Negative to 0.8	Chlorine	0-7.3	Chlorine
Advanced systems									
Low speed/residual	-----	5.6-37.5	Meat packing	Negative	--------	Negative to 10 6	Newsprint	0-9.0	Writing paper
Low speed/coal	-----	5.5-36.6	Meat packing	Negative	--------	0.2-31.2	Newsprint	2.6-14.7	Newsprint
Medium speed	GE	16.8-37.4	Malt beverages	Negative	Writing paper	Negative to 7.9	Chlorine	0-9	Chlorine
Medium speed with heat pump		9.1-39.7	Meat packing; malt beverages	Negative to 16	Writing paper	Negative to 11.3	Newsprint	0-14	Chlorine
High speed	UTC	5.5-47.6	Chlorine	1.9-29.6	Chlorine	Negative to 11.2	Chlorine	0-12.1	Steel

[a]No power export allowed.
[b]Power export allowed.



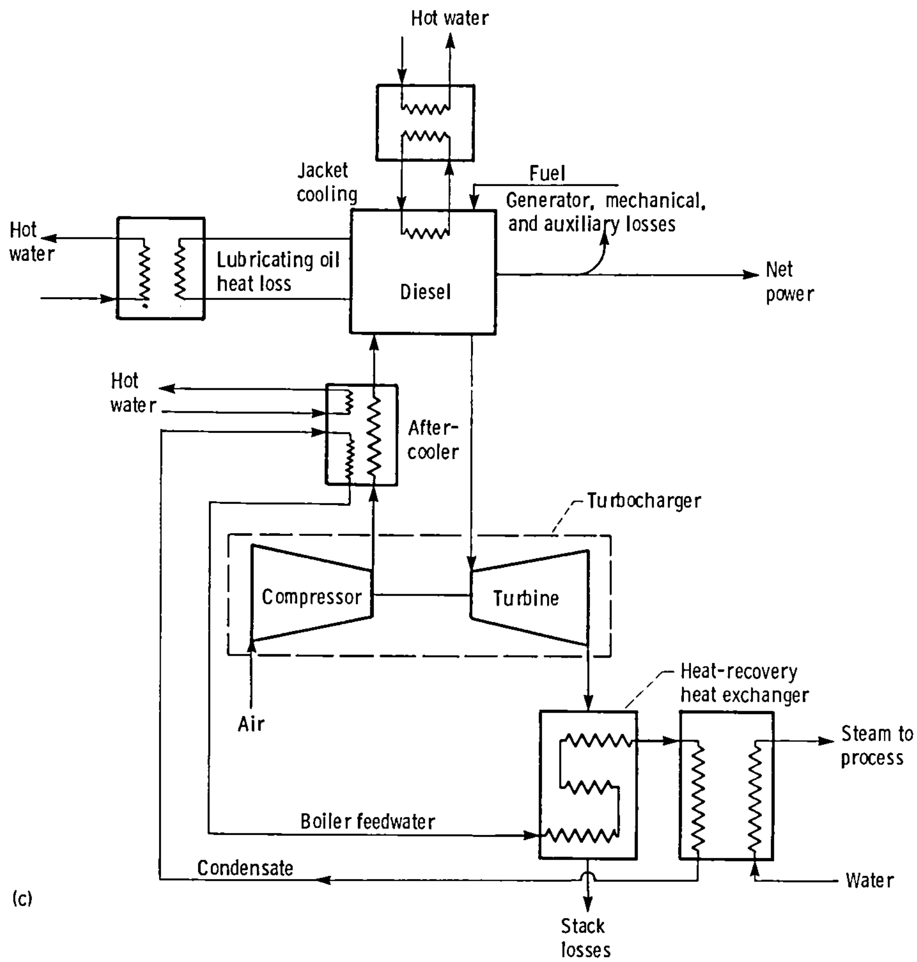
(a) GE diesel.

Figure 5.2-1. - Schematics of diesel engine systems.



(b) GE diesel with heat pump.

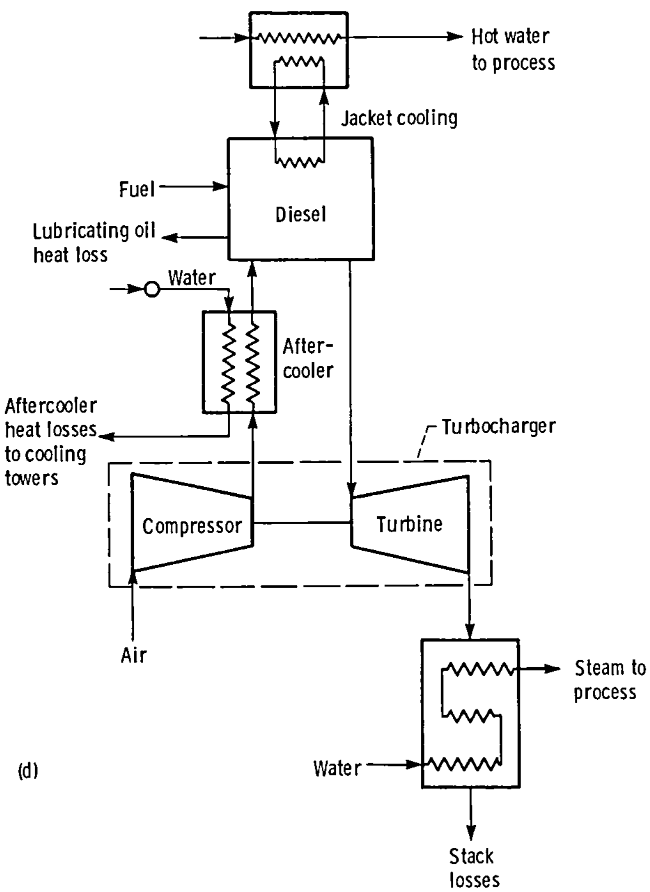
Figure 5.2-1. - Continued.



(c)

(c) UTC low-speed diesel.

Figure 5.2-1. - Continued.



(d) UTC high-speed diesel.

Figure 5.2-1. - Concluded.

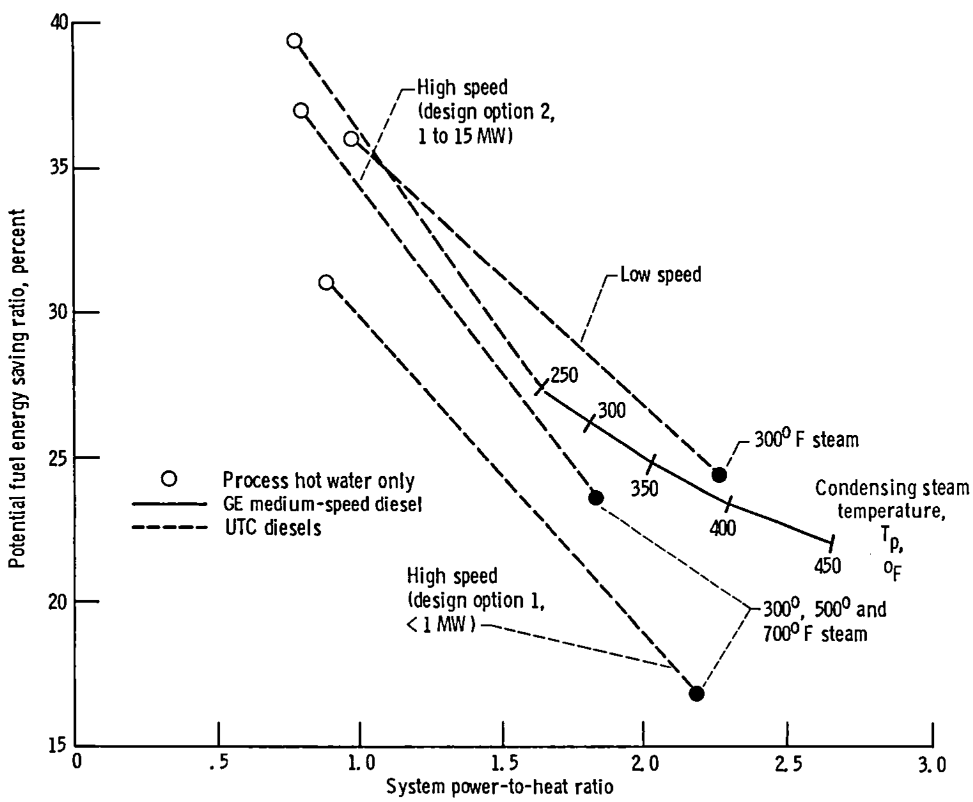


Figure 5.2-2. - Performance characteristics of state-of-the-art diesel systems.

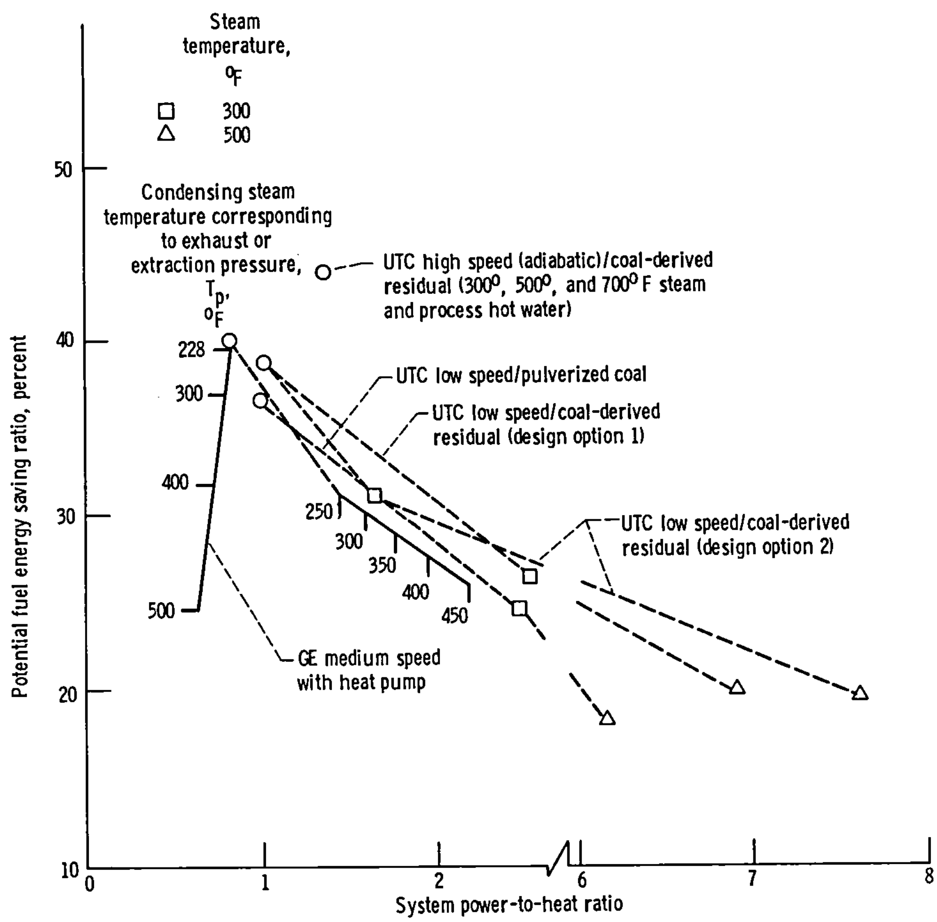
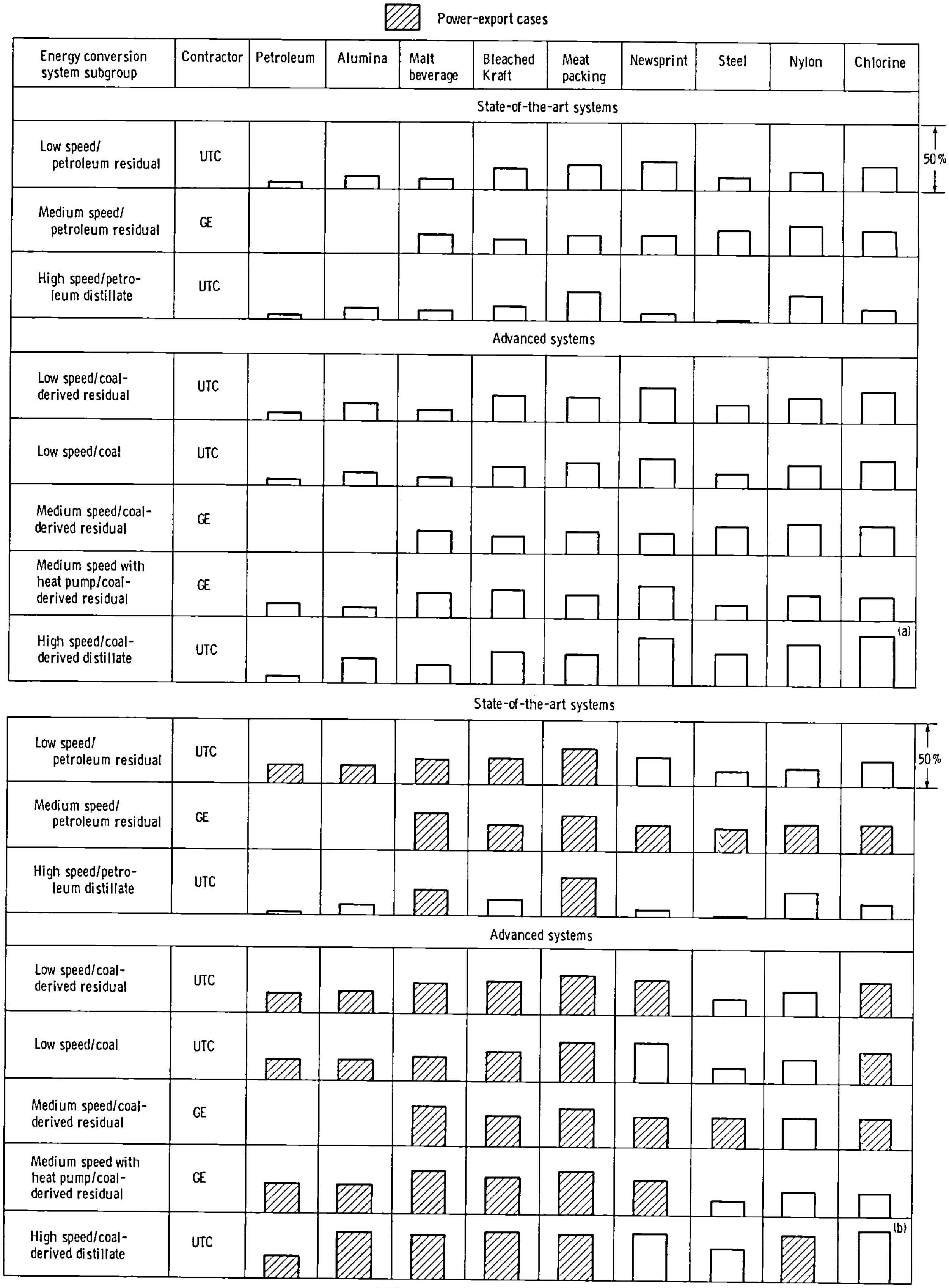
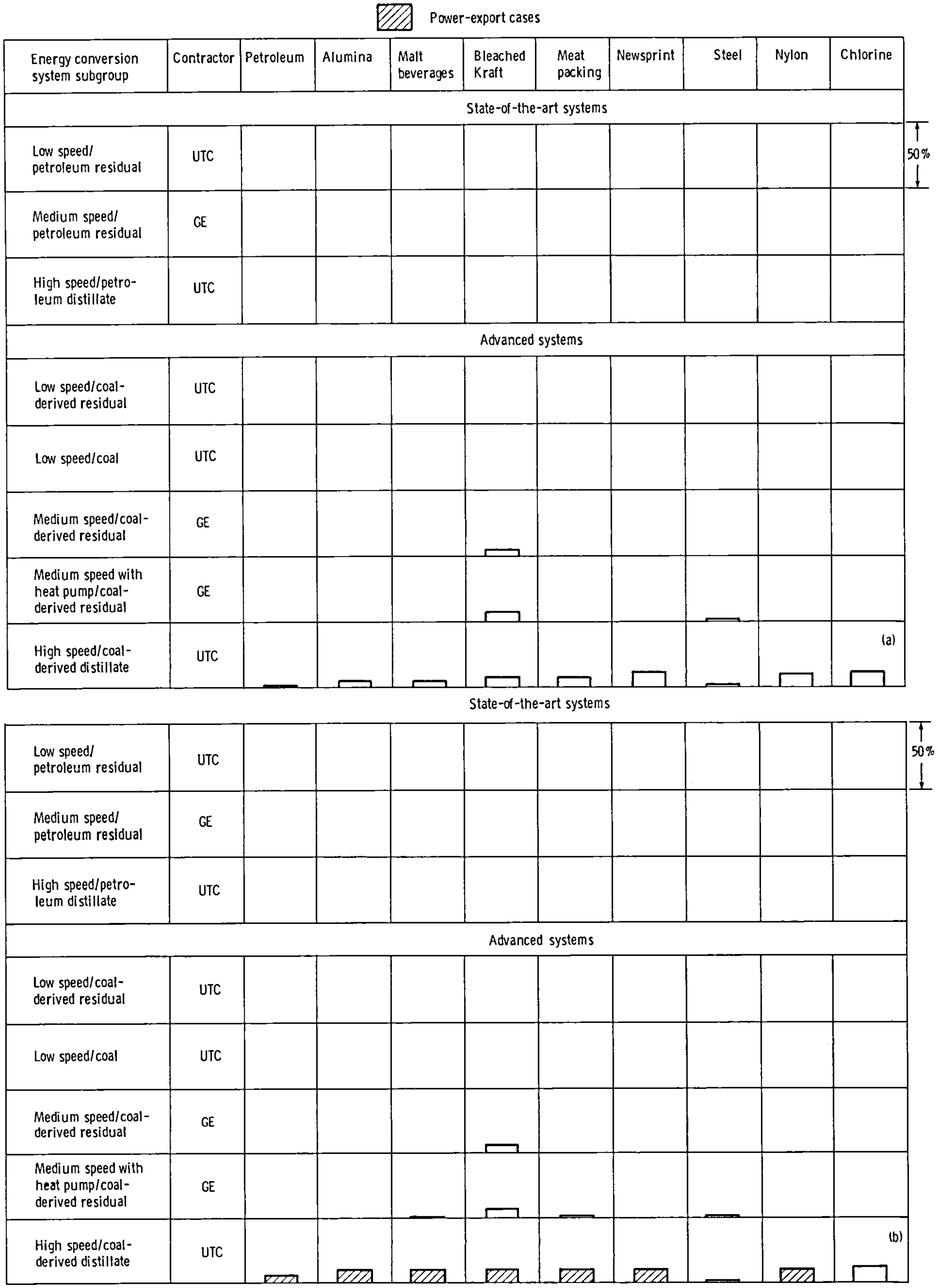


Figure 5.2-3. - Performance characteristics of advanced diesel systems.



(a) No power export allowed.
(b) Power export allowed.

Figure 5.2-4. - Fuel energy saving ratio for diesel engine systems. (Blanks denote all negative values.)



(a) No power export allowed.
(b) Power export allowed.

Figure 5.2-5. - Emissions saving ratio for diesel engine systems. (Blanks denote all negative values.)

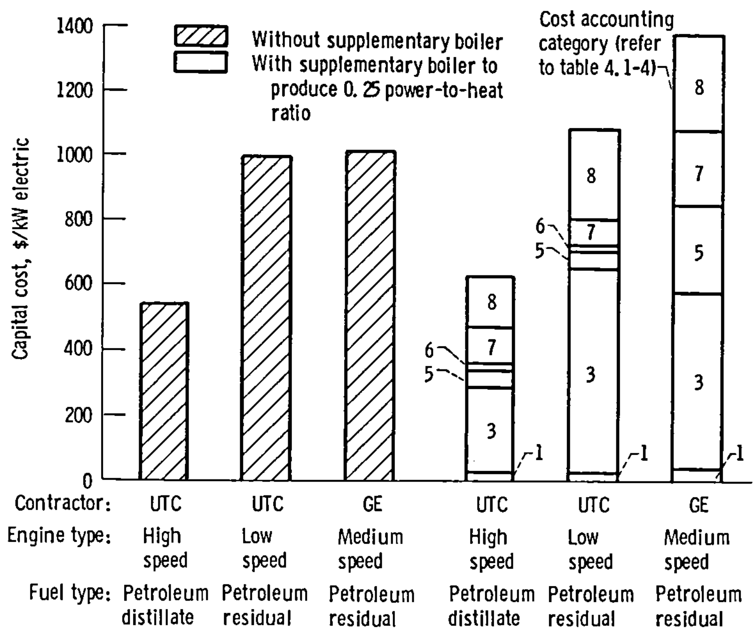


Figure 5.2-6. - Capital costs for diesel engine systems. Electricity generated, 10 MW; process steam temperature, 300° F.

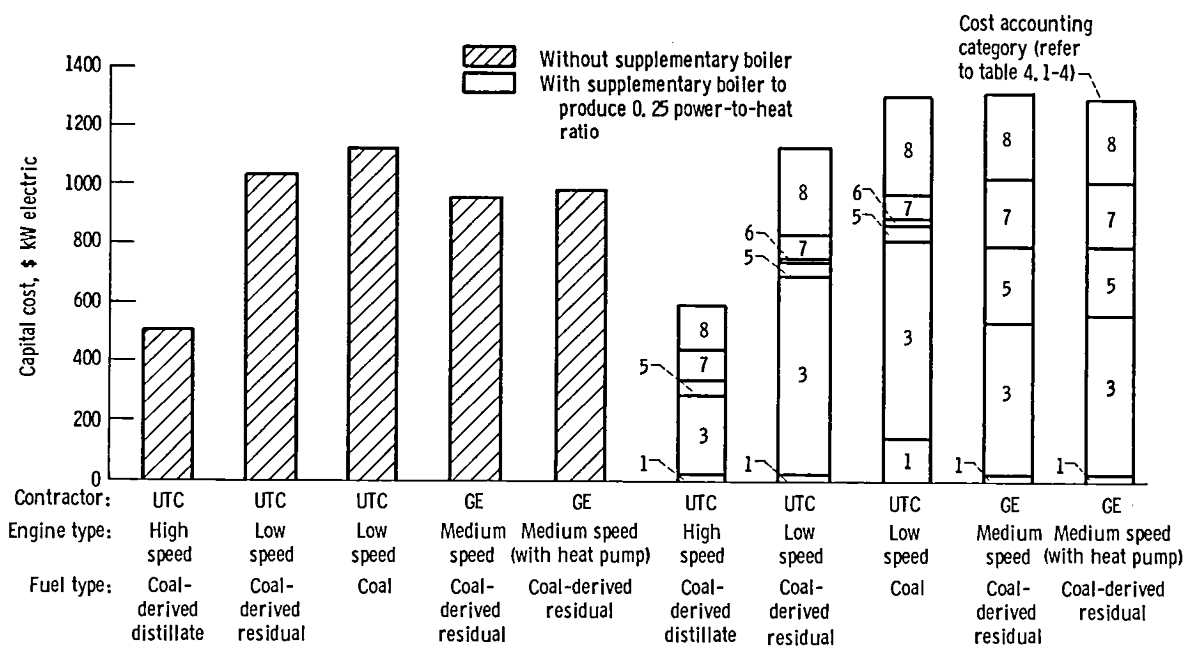


Figure 5.2-7. - Capital costs for advanced diesel engine systems. Electricity generated, 10 MW; process steam temperature, 300° F.

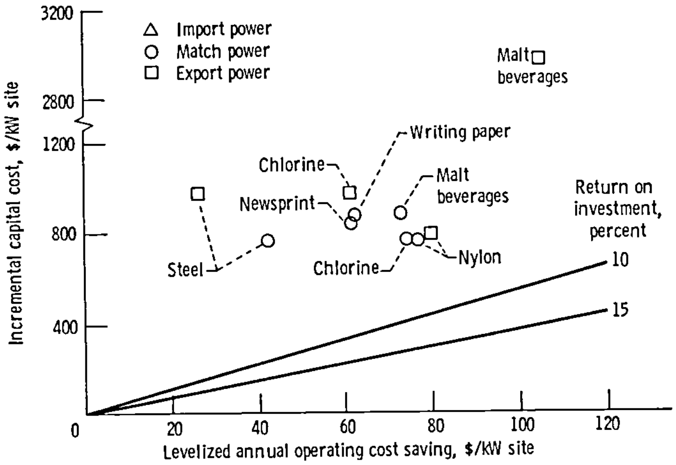
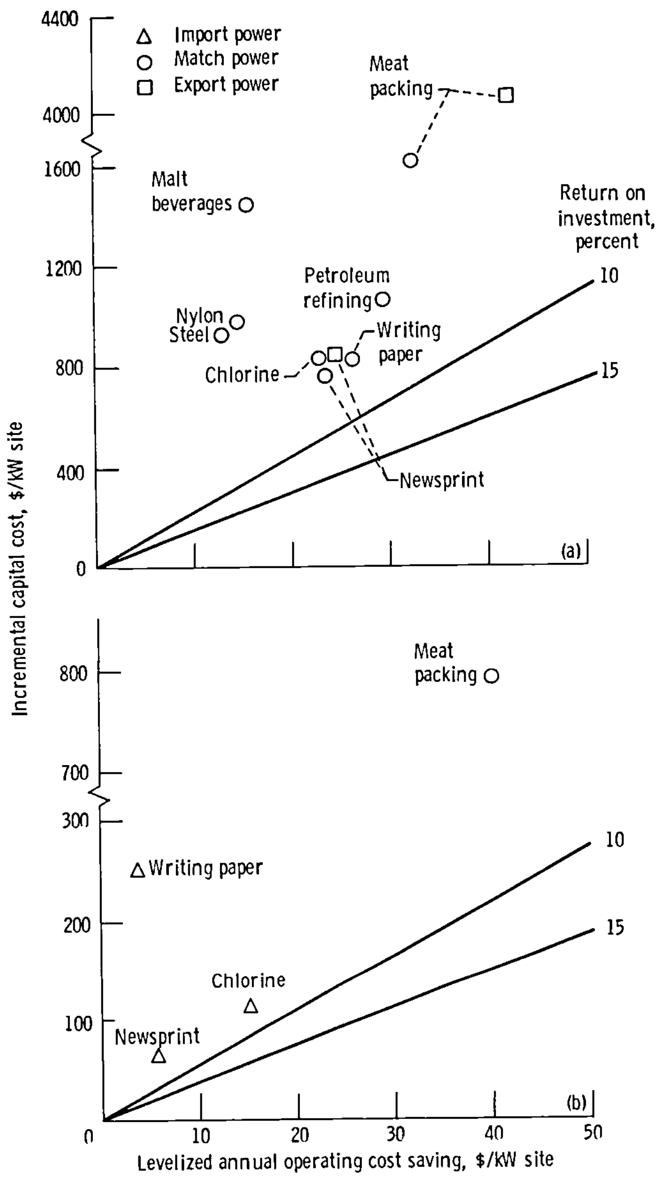
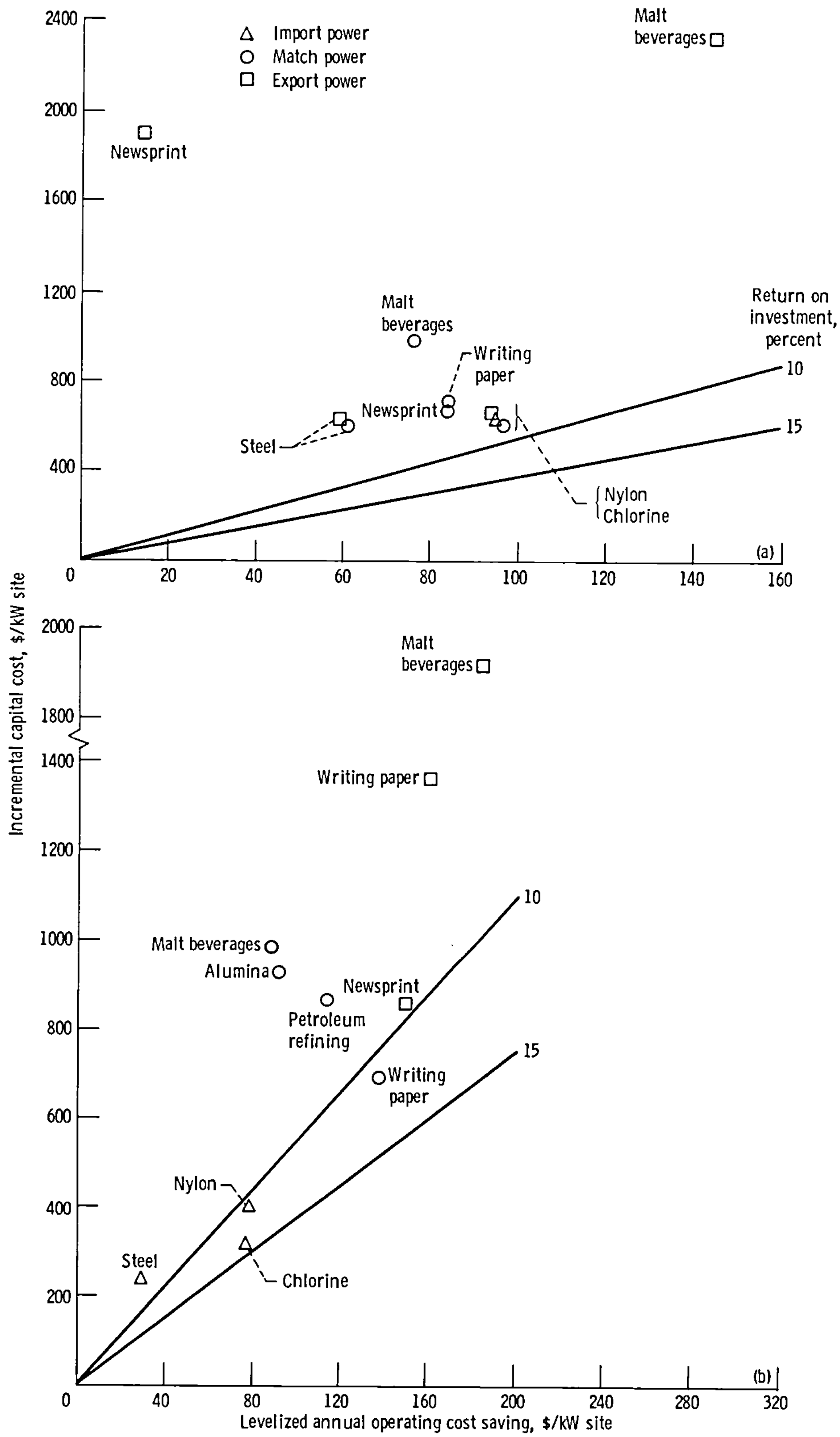


Figure 5.2-8. - Incremental capital cost as a function of levelized annual operating cost saving for GE's state-of-the-art medium-speed diesel engine/ petroleum residual system.



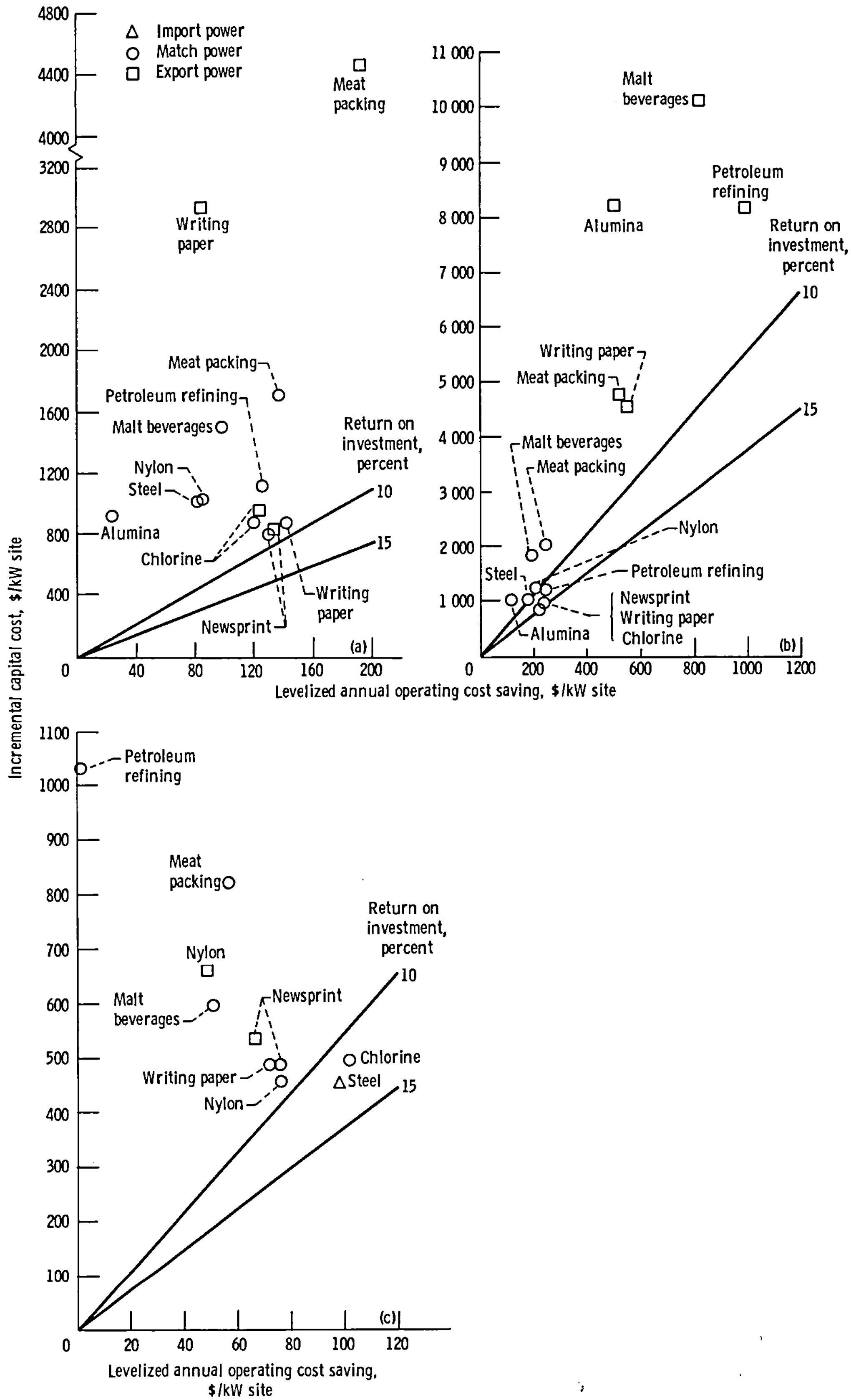
(a) Low-speed diesel/residual.
(b) High-speed diesel/distillate.

Figure 5.2-9. - Incremental capital cost as a function of levelized annual operating cost saving for UTC's state-of-the-art diesel engine system.



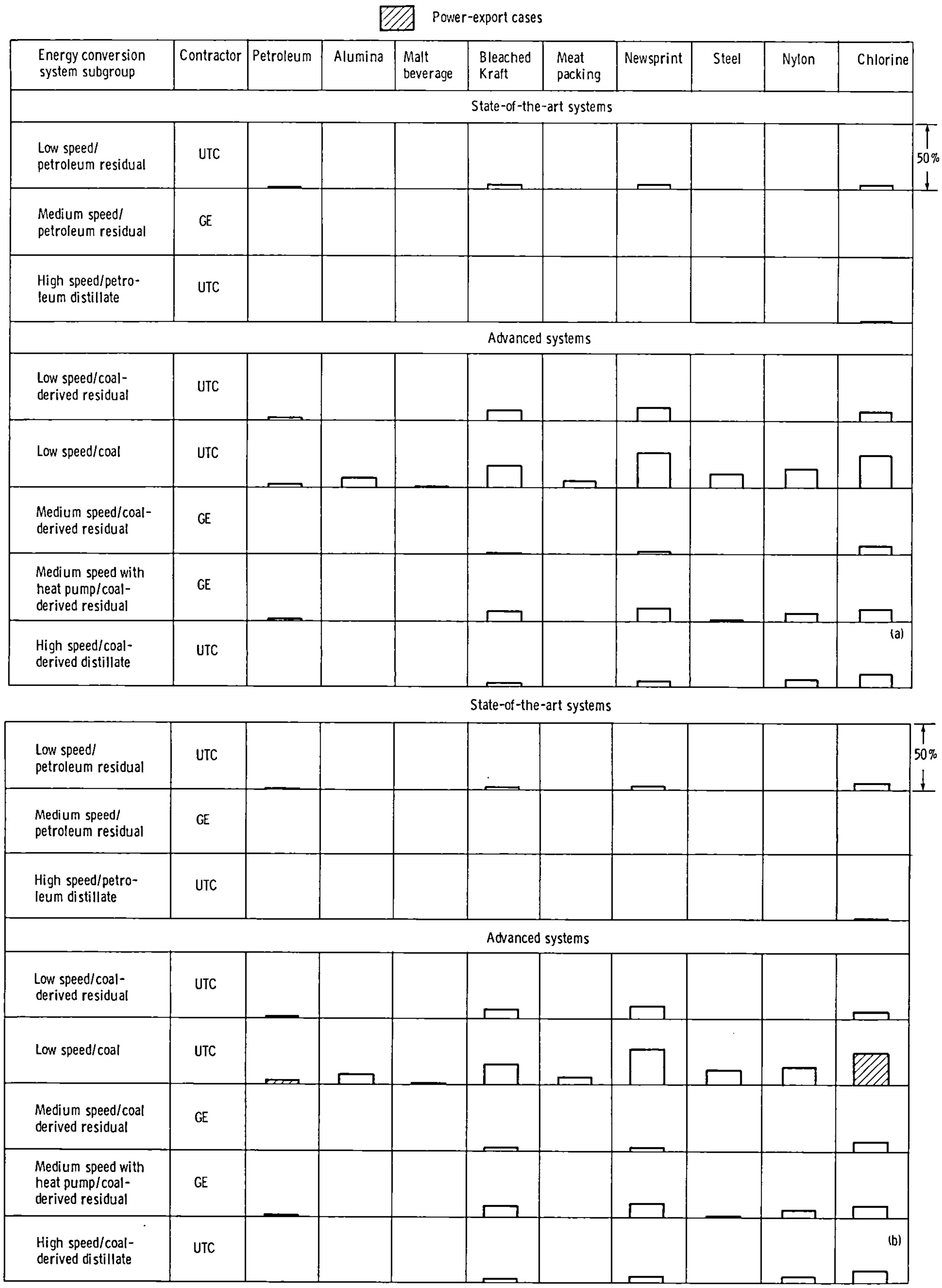
(a) Without heat pump.
(b) With heat pump.

Figure 5.2-10. - Incremental capital cost as a function of levelized annual operating cost saving for GE's advanced medium-speed diesel engine/coal-derived residual system.



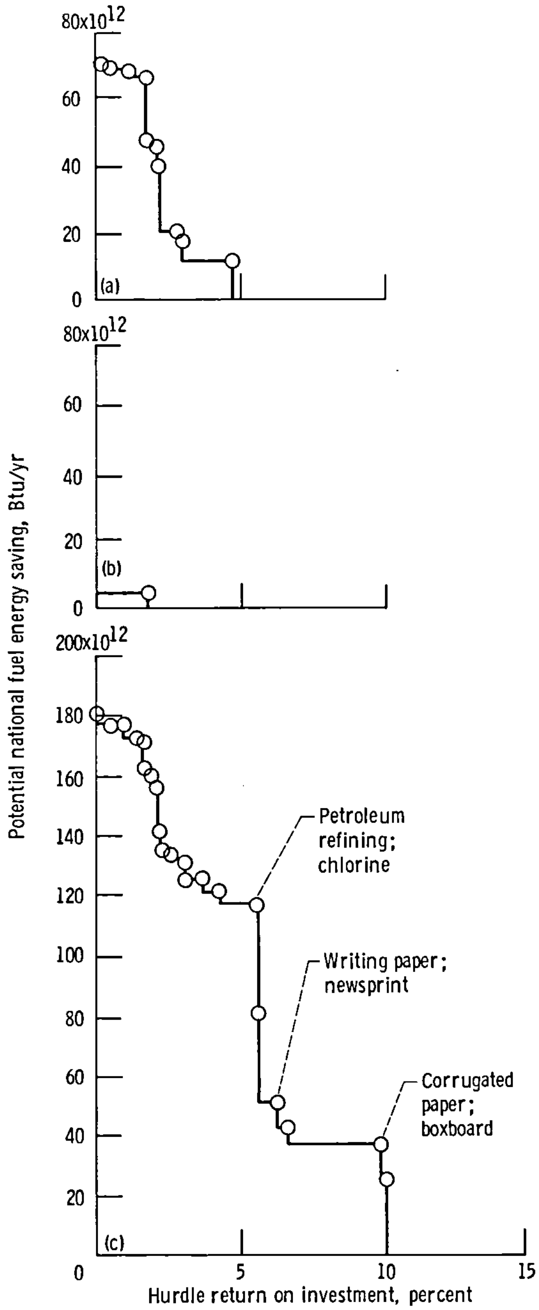
(a) Low-speed diesel/coal-derived residual.
(b) Low-speed diesel/coal.
(c) High-speed diesel/coal-derived distillate.

Figure 5.2-11. - Incremental capital cost as a function of levelized annual operating cost saving for UTC's advanced diesel engine system.



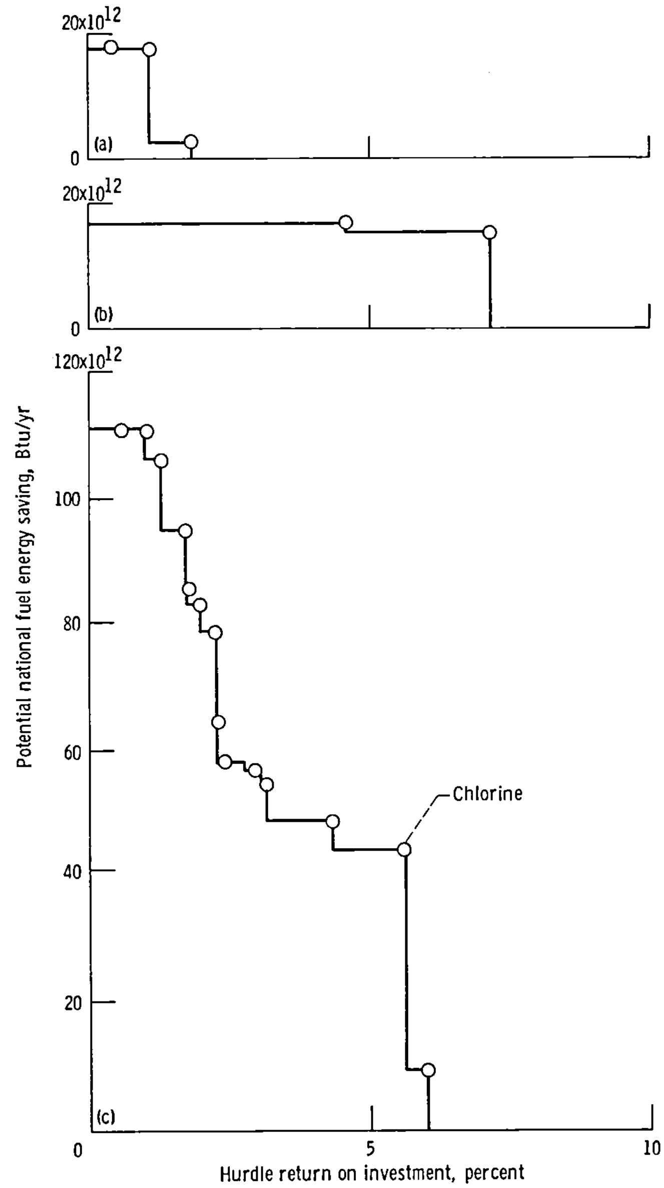
(a) No power export allowed.
(b) Power export allowed.

Figure 5.2-12. - Levelized annual energy cost saving ratio for diesel engine systems. (Blanks denote all negative values.)



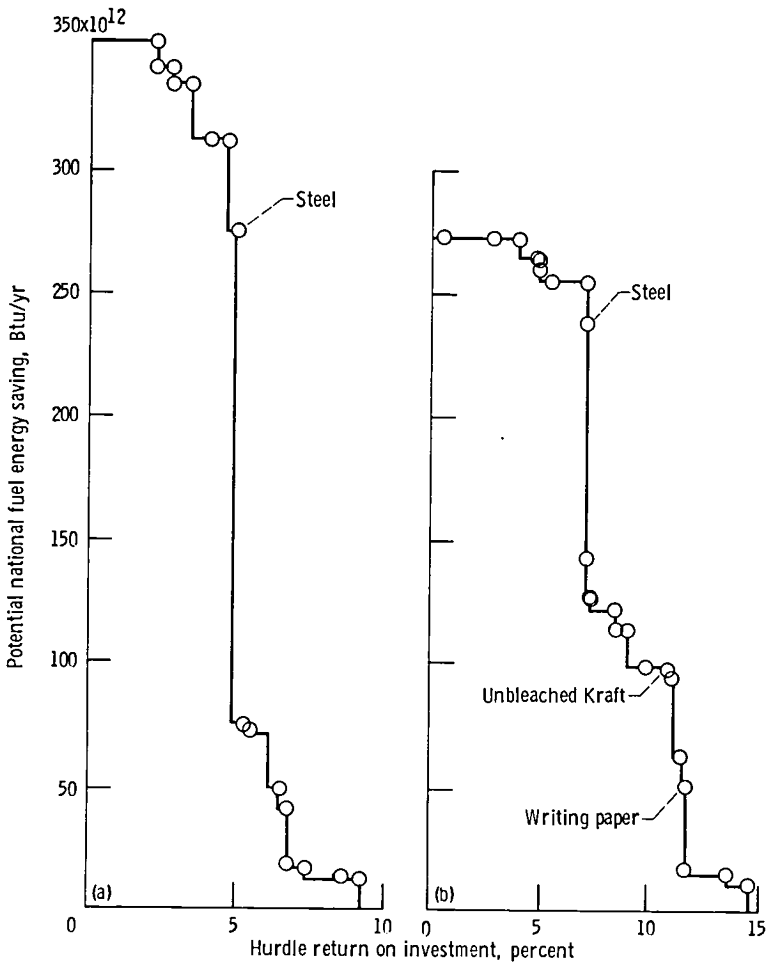
(a) GE's medium-speed diesel/residual.
(b) UTC's high-speed diesel/residual.
(c) UTC's low-speed diesel/residual.

Figure 5.2-13. - Potential national fuel energy saving as a function of hurdle return on investment for state-of-the-art diesel engine systems. (No power export allowed.)



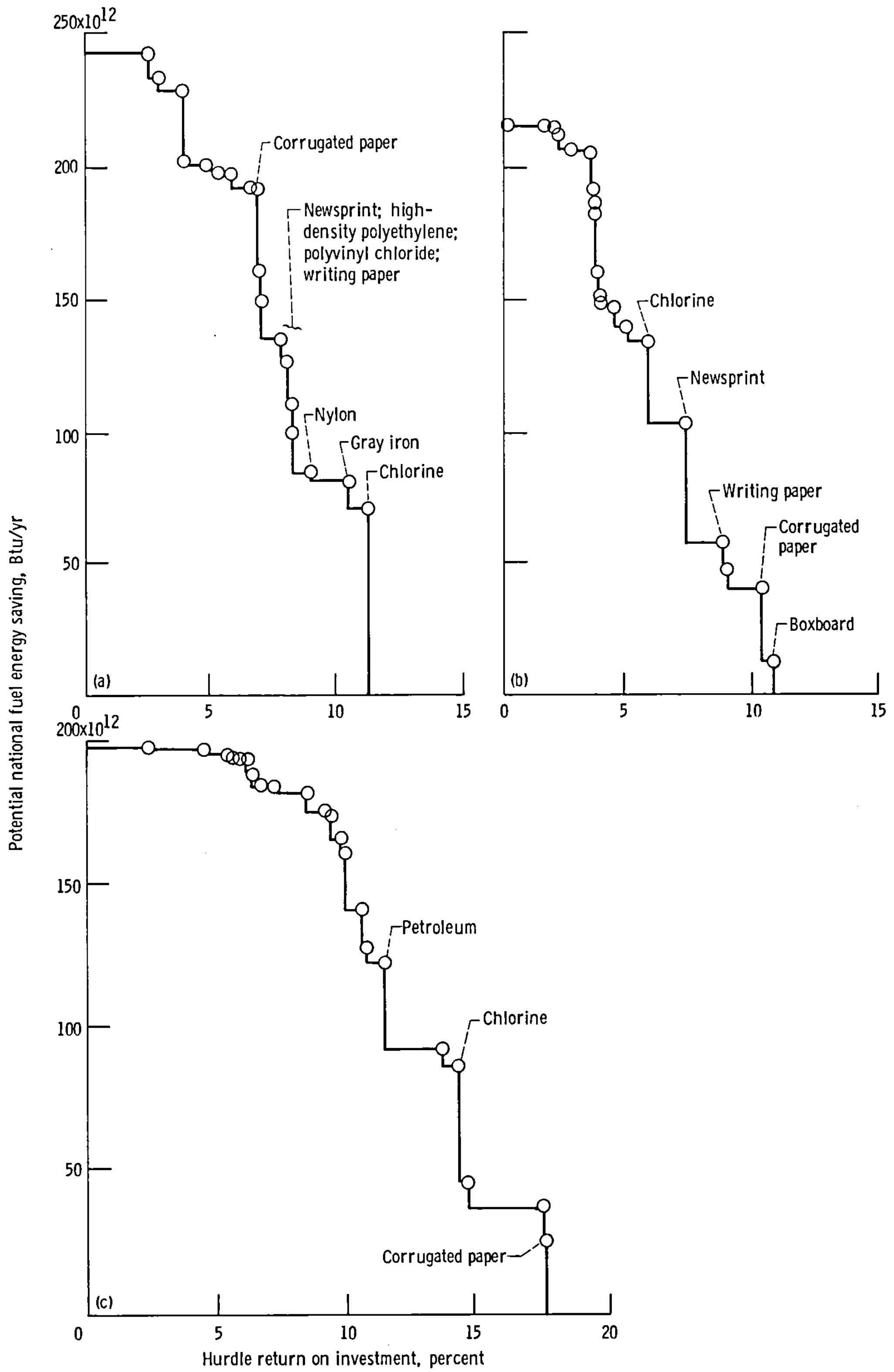
(a) GE's medium-speed diesel.
(b) UTC's high-speed diesel.
(c) UTC's low-speed diesel.

Figure 5.2-14. - Potential national fuel energy saving as a function of hurdle return on investment for state-of-the-art diesel engine systems. (Power export allowed.)



(a) Without heat pump.
(b) With heat pump.

Figure 5. 2-15. - Potential national fuel energy saving as a function of return on investment for GE's advanced medium-speed diesel engine/coal-derived residual systems.



(a) High-speed diesel.
(b) Low-speed diesel/coal-derived residual.
(c) Low-speed diesel/coal.

Figure 5.2-16. - Potential national fuel energy saving as a function of hurdle return on investment for UTC's advanced diesel engine systems. (No power export allowed.)

5.3 OPEN-CYCLE GAS TURBINE SYSTEMS

Joseph J. Nainiger and Yung K. Choo

5.3.1 Configurations and Parameters

The parameters considered for each contractor are shown in table 5.3-1. For the state-of-the-art simple-cycle configuration both contractors considered petroleum-distillate-fueled gas turbines at a turbine inlet temperature of 2000° F. In addition, GE studied a petroleum-residual-fueled gas turbine at 1750° F. The lowered turbine inlet temperature was chosen by GE to avoid hot corrosion with the dirtier fuel. Both contractors assumed air cooling for all of their state-of-the-art cases. UTC investigated supplementary firing for both state-of-the-art and advanced gas turbines; GE did not employ supplementary firing in any of their cases. A schematic for the simple-cycle, liquid-fueled gas turbines is shown in figure 5.3-1.

For the advanced simple-cycle gas turbines both contractors studied coal-derived residual fuel firing. GE investigated turbine inlet temperatures of 2200° F with air cooling and 2600° F with water cooling, and UTC assumed 2500° F gas turbines with air cooling. In addition, UTC considered externally fired gas turbines burning coal and a gas turbine integrated with a low-Btu coal gasifier. One group of coal-fired cases consists of a pressurized-fluidized-bed coal combustor with in-bed desulfurization by means of dolomite sorbent, a bed temperature of 1650° F, and a turbine inlet temperature of 1600° F. A schematic of this system is shown in figure 5.3-2(a). Part of the air exiting the gas turbine compressor is used to fluidize the bed, the remaining air is heated in tubes within the bed. Process steam or hot water is produced by recovering heat from the gas turbine exhaust. One of the design options considered by UTC consisted of raising additional process steam from the fluidized bed (not shown in the figure).

Another group of coal-fired cases employs an atmospheric fluidized bed (AFB) with in-bed desulfurization by means of limestone sorbent. The bed operating temperature is 1600° F with a corresponding turbine inlet temperature of 1500° F. A schematic of this system is shown in figure 5.3-2(b). Here, air from the compressor exit is heated through tubes within the furnace. The bed is fluidized by a portion of the turbine exhaust air. The remaining turbine exhaust is used to produce steam or hot water for process requirements. Also, for all cases considered with AFB, varying amounts of process steam or hot water are produced within the fluidized bed.

The open-cycle gas turbine with integrated coal gasifier consists of an entrained-bed, low-Btu gasifier with a cold-gas cleanup system integrated with an advanced, high-temperature gas turbine. A schematic of this system is shown in figure 5.3-2(c).

In addition to the advanced, simple-cycle gas turbine GE investigated recuperated cycles with high turbine inlet temperatures and recuperator effectivenesses of 0.60 and 0.85. Only coal-derived distillate fuel was considered for these cases since GE felt that the dirtier coal-derived residual fuel would cause fouling of the recuperator surfaces. A schematic for this system is shown in figure 5.3-3.

Another configuration investigated by both contractors was the steam-injected simple cycle burning coal-derived residual fuel. A schematic is shown in figure 5.3-4. Part of the steam raised by the gas turbine exhaust is injected into the gas turbine combustor and thus results in higher power output and higher electrical efficiency than the simple-cycle configuration without steam injection. Both contractors considered one turbine inlet temperature and one compressor pressure ratio with different steam-to-combustor-air mass flow ratios. In the GE analysis injection of superheated and saturated steam with a steam-to-air ratio of 0.1 was investigated, along with injection of superheated steam at a steam-to-air ratio of 0.15. In the UTC analyses steam-to-air ratios of 0.05 and 0.1 with injection of superheated steam were considered.

In addition to the liquid-fueled, steam-injected gas turbines UTC studied coal-fired steam-injected turbines with either an atmospheric fluidized bed or a pressurized fluidized bed. Schematics for these two systems are shown in figure 5.3-5. Here, some steam raised by the turbine exhaust is injected into the compressor exit airstream ahead of the furnace. The steam-to-air mixture is heated within the fluidized bed furnace. The steam-to-air ratios are the same as those used for the residual-fueled cases. For the AFB system (fig. 5.3-5(a)) the air to fluidize the bed is supplied by a separate blower instead of using part of the turbine exhaust as is done in the non-steam-injection, coal-fired gas turbine cases. The bed temperature, turbine inlet temperature, and compressor pressure ratios are the same as those used in the simple-cycle, coal-fired cases.

5.3.2 Cogeneration System Performance

5.3.2.1 Fuel Energy Saving Ratio

The ratios of power to process heat produced for a range of process steam (or hot water) conditions, together with the cogeneration fuel energy savings that would be achieved if those power-to-heat ratios matched the process needs are shown for all of the open-cycle gas turbine configurations in figures 5.3-6 to 5.3-11. As discussed in appendix D, if the site-required power-to-heat ratio differed from the ratio provided by the system as shown in these figures, the fuel saving in most cases would be lower than shown. Only if the process requires a power-to-heat ratio lower than that produced by the system and a match-heat - export-power strategy is used, will the fuel energy saving ratio equal the value shown in the figure. The open circles represent cogeneration performance if the process requirement is assumed to be only hot water.

The results for the state-of-the-art simple-cycle gas turbine are shown in figure 5.3-6. UTC design options 1, 2, and 3 correspond to compressor pressure ratios of 10, 12, and 14, respectively. UTC design option 4 is a pressure-ratio-14 gas turbine with supplementary firing. Since extra fuel is burned in the heat-recovery steam generator to produce a greater amount of steam, the power-to-heat ratio of this design option is lower than those of the other three UTC design options. Comparison of the results for UTC design option 1 with the GE distillate-fueled case (both having turbine inlet temperatures of 2000° F and pressure ratios of 10) indicates the same FESR and approximately the same power-to-heat ratio for both cases. The GE residual-fueled case has slightly lower FESR and higher power-to-heat ratio because of its lower turbine inlet temperature.

Results for the advanced simple-cycle gas turbine burning coal-derived residual fuel are shown in figure 5.3-7. Here, design options 1, 2, and 3 correspond to compressor pressure ratios of 14, 16, and 18, respectively. Design options 4 and 5 represent supplementary fired cases at two different power-to-heat ratios. The GE cases include three air-cooled cases at different compressor pressure ratios and one water-cooled case. The UTC cases have higher potential fuel energy saving than the GE cases because of their higher turbine inlet temperatures (2500° F for UTC, 2200° F for GE). Although the GE water-cooled case has a turbine inlet temperature (2600° F) higher than that of UTC, it does not have as high a potential fuel energy saving since a considerable amount of potentially recoverable heat is lost in water cooling the turbine blades. For both contractors the advanced simple-cycle gas turbines burning coal-derived residual fuel offer higher potential fuel energy savings than the state-of-the-art systems.

The potential fuel energy saving versus the system power-to-heat ratio is shown for advanced, indirectly fired, simple-cycle gas turbines burning coal in figure 5.3-8. For the pressurized-fluidized-bed cases design options 1, 2, and 3 correspond to compressor pressure ratios of 6, 8, and 10, respectively. Design option 4 is a system with a pressure ratio of 10 with additional process steam production within the fluidized bed, resulting in the lower power-to-heat ratio shown. The two gasifier design options consist of a 2400° F, pressure-ratio-17 gas turbine (design option 1) and a 2500° F, pressure-ratio-18 gas turbine (design option 2). The three design options for the AFB system represent different amounts of process steam production in the bed. In design option 1 all of the turbine exhaust is used as combustion air for the AFB, resulting in the maximum amount of steam production (all of it being raised in the bed). In design options 2 and 3, two-thirds and one-half, respectively, of the exhaust gas is used as bed combustion air, thus reducing the amount of steam raised in the bed. Although the exhaust gas not used as combustion air is used to raise steam in a heat-recovery steam generator, the total amount of process steam raised is less for these two design options than for design option 1.

As shown in figure 5.3-8 the PFB systems have the highest power-to-heat ratios, followed by the gasifier systems, with the AFB systems having the lowest power-to-heat ratios. The coal-fired systems have lower potential fuel energy savings and power-to-heat ratios than the liquid-fueled, simple-cycle systems (fig. 5.3-7).

The potential fuel energy saving and power-to-heat ratio are shown for GE's advanced recuperated gas turbine system in figure 5.3-9. Although 12 separate cases were considered by GE, only 4 are shown there as being representative of the results. These cases are at higher power-to-heat ratios than the advanced simple-cycle cases shown in figure 5.3-7.

The results for the advanced, steam-injected, simple-cycle gas turbine are shown in figure 5.3-10. Results for the GE system with a steam-to-combustor-air ratio of 0.15 are not shown, since it has a power-to-heat ratio of 29, thus making it a poor match for all industries. For GE the use of superheated steam results in higher power-to-heat ratio and slightly lower potential fuel energy saving than in the case where saturated steam is injected. For UTC the case with the lower steam-to-air ratio has higher potential fuel energy saving and lower power-to-heat ratio. The potential fuel energy savings for the UTC cases are higher than GE's because of the higher UTC turbine inlet temperature

and compressor pressure ratio. Of all of the steam-injection cases shown, design option 2 is the best with respect to fuel energy saving when matched to the various processes. For both contractors the advanced steam-injected gas turbines have lower potential fuel energy saving and higher power-to-heat ratio than the advanced simple-cycle cases burning coal-derived residual fuel shown in figure 5.3-7.

Finally, the potential fuel energy saving and power-to-heat ratio for the advanced, coal-fired steam-injected gas turbines studied by UTC are shown in figure 5.3-11. As shown, of the four cases, three have negative potential fuel energy saving. Although the electrical efficiencies for these cases are higher than those for the coal-fired gas turbines shown previously, much less heat is recovered for process use. A considerable amount of the waste heat is used to raise steam for injection, leaving little or no heat available for process steam. Only the PFB case with the lower steam-to-air ratio offers a positive potential fuel saving.

A number of conclusions can be drawn from these figures on how the various configurations would match against the different industries. The advanced simple-cycle cases burning coal-derived residual fuel would match well with industries having power-to-heat ratios of 0.5 to 0.8. The recuperated and steam-injected gas turbines burning liquid fuel would match well with industries having higher power-to-heat ratios. The coal-fired, simple cycle gas turbines would tend to match well with industries having lower power-to-heat ratios. The coal-fired, steam-injected gas turbines would be expected to have the lowest fuel energy savings when matched to the various industries. Also, all of the coal-fired cases (simple and steam injected) should have better fuel energy savings with industries that require hot water.

Fuel energy saving ratio results of the open-cycle gas turbine systems matched to nine representative industries are shown in figures 5.3-12 and 5.3-13. The characteristics of these processes are listed in section 4.4. The processes are listed in these two figures in ascending order of power-to-heat ratio. In part (a) of each figure only matching strategies that produce no excess power are included. All matching strategies are considered in part (b); the one that yields the highest FESR was used for these figures.

The FESR results are shown for the liquid-fueled, open-cycle gas turbine systems in figure 5.3-12. In part (a), where export is excluded, the fuel savings shown are generally most attractive for those processes that require a power-to-heat ratio near that produced by the energy conversion system. This corresponds to the processes in the middle columns for both contractors' simple-cycle cases, which were shown in figure 5.3-7 to generally yield power-to-heat ratios from 0.5 to 0.8.

One exception to this is the UTC chlorine process. In this process some hydrogen byproduct fuel is used to supply a portion of the process heat requirement in the noncogeneration case. However, in the cogeneration case more hydrogen byproduct fuel is used in the gas turbine, thereby reducing the amount of residual fuel used and thus increasing the FESR. For the recuperated and steam-injected systems the fuel savings are generally most attractive for the processes in the right columns, which have the highest power-to-heat ratios. An exception to this is the steel industry, where a considerable amount of byproduct coke-oven gas is available as fuel. In this case the coke-oven gas

can be used in the noncogeneration onsite boiler and in the cogeneration supplementary boiler, but not in the gas turbine. Because this byproduct fuel cannot be used, the FESR is lower.

The fuel energy saving results obtained for these nine processes when export of power is allowed are shown in figure 5.3-12(b). The FESR results are improved over those in part (a) in many cases where using a larger power system and making excess power result in a greater amount of heat recovery for process use. The cases that involve export are denoted by crosshatched bars; the others correspond to a match-power or import situation and are the same as in part (a). The lower the site-required power-to-heat ratio in relation to that produced by the energy conversion system, the greater the amount of excess power produced in a match-heat strategy. This will affect the economic results as illustrated in later figures and parametrically in appendix D. Since the recuperated and steam-injected gas turbines produce a higher ratio of power to heat (figs. 5.3-9 and 5.3-10) than the simple-cycle cases (fig. 5.3-7), the amount of export power is generally greater for those two configurations.

The FESR results for the coal-fired gas turbine systems studied by UTC are shown in figure 5.3-13. In part (a) the results for those strategies excluding export of power are shown. The high value of FESR for the PFB, AFB, and gasifier cases in the bleached Kraft and newsprint industries is the result of a UTC assumption that a black-liquor byproduct fuel derived from these processes can be burned in the PFB, AFB, and gasifier. The burning of this liquor is commonly done in the paper industry to raise process steam. However, when this is done, a special recovery unit on the steam boiler recovers valuable chemicals that are recycled for process use. UTC has made no provision to recover these chemicals when burning the liquor in the PFB, AFB, or gasifier. Also, as shown in the figure, the FESR's for the coal-fired, steam-injected gas turbines are the lowest of any of the configurations, as was discussed previously (fig. 5.3-11). The steam-injected gas turbine with AFB has positive FESR when matched with the petroleum process because gas turbine exhaust gas is used to satisfy hot-gas (direct heat) process requirements. Positive FESR's in the malt beverage and meat packing processes are due to the recovery of heat in the form of hot water for process use. The use of byproduct fuel in the bleached Kraft, newsprint, and chlorine processes results in a positive FESR when the steam-injected AFB gas turbine is matched with these industries.

The FESR's for all matching strategies, including those that export power, are shown in figure 5.3-13(b). Generally, improvements in FESR over part (a) are seen in the processes with low power-to-heat ratios, represented by the columns on the left. Aside from bleached Kraft and newsprint the industry with the highest FESR is the petroleum process. This process needs a considerable amount of direct process heat, and UTC assumed that a large portion of the turbine exhaust could be used to satisfy that requirement. This results in very good heat recovery from the gas turbine and the resulting high FESR.

5.3.2.2 Emissions Saving Ratio

The emissions saving ratios for the open-cycle gas turbine systems matched to the nine representative industrial processes are shown in figures 5.3-14 and 5.3-15. The EMSR, defined in section 4.3, is the percentage reduction in emissions when both the utility site and the industrial site are considered. The results shown in figures 5.3-14 and 5.3-15 correspond to the total of NO_x,

SO_x, and particulate emissions and are calculated by assuming the use of a coal-derived residual fuel in the noncogeneration onsite boiler. For the UTC cases coal was assumed to be used at the utility. For the GE cases a fuel mix consisting of 77 percent coal and 23 percent coal-derived residual fuel was assumed to be used by the utility. In addition to the amount of fuel saved, the emissions saving depends strongly on the combustion characteristics of the system and the type of fuel used. The emissions per unit of fuel consumed are shown in table 5.3-2 for both contractors. In figure 5.3-14 the EMSR's for the state-of-the-art systems using petroleum distillate fuel are obviously highest because of the lower emissions rates shown in table 5.3-2. For systems using coal-derived residual fuel the estimates for SO_x and particulates are approximately the same for both contractors, but the NO_x estimate for UTC's advanced simple-cycle gas turbine is substantially lower than that estimated by GE. UTC assumed that gas turbine combustors would be developed within the time frame of CTAS (1985-2000) to control the NO_x formed by the fuel-bound nitrogen in the coal-derived residual fuel. GE assumed less success in controlling the NO_x from fuel-bound nitrogen. This, plus the fact that GE assumed that 23 percent of the fuel burned by the utility is coal-derived residual resulted in lower EMSR's for GE. The EMSR's for the coal-fired gas turbines (fig. 5.3-15) compare reasonably well with those for the UTC liquid-fueled gas turbines in figure 5.3-14 and are actually higher than those for gas turbines using the GE coal-derived residual fuel inspite of burning the supposedly dirtier coal fuel. There are two reasons for this. The first is that for the coal-fired cases matched with the bleached Kraft and newsprint processes, no emissions were assumed by UTC for the considerable amount of byproduct black-liquor fuel burned in the system heat source. The second reason is found in table 5.3-2. The total emissions from the PFB and AFB heat sources are approximately the same as the emissions from the UTC gas turbine burning coal-derived residual fuel and substantially less than those estimated by GE.

5.3.2.3 Capital Cost

A capital cost comparison between the contractors open-cycle gas turbine cogeneration systems is shown in figures 5.3-16 to 5.3-21. Capital costs in dollars per kilowatt of electricity produced by the systems are shown for a 10-MW-electric system with recovery of heat as 300° F steam. Each contractor estimated the costs according to the cost accounts described in section 4.1. The bar graphs include all costs of equipment and installation for a 10-MW-electric system including all fuel-handling, storage, and processing equipment and all heat recovery equipment.

Because each cogeneration system produces a different power-to-heat ratio, and thus would need a different size and cost supplementary boiler when matched to a common process, bar graphs are also shown that include a supplementary boiler large enough to yield a power-to-heat ratio of 0.25. As indicated by figure 3.2-2, this ratio is near the mean value for all of the processes studied in CTAS.

A capital cost comparison between the contractors' state-of-the-art simple-cycle gas turbines burning petroleum distillate fuel is shown in figure 5.3-16. There are substantial cost differences in the contractors' estimates for the supplementary boiler (category 5), for balance of plant (category 7), and for contingency and architect and engineering (A&E) services (category 8).

The duty for the supplementary boilers is about the same for both contractors, yet the capital cost for the GE boiler is about six times that for the UTC boiler. Likewise, the GE balance-of-plant cost is about 12.5 times that of UTC. It will be shown in later figures that these two cost estimate differences predominate in comparisons of all of the configurations. Differences in cost category 8 (contingency and A&E services) are due to two factors. First, since these adders are a certain percentage of the total accumulative costs of the other cost categories, the category 8 costs will reflect differences in these accumulated costs. Second, as mentioned in section 4.2, different percentages were used by the contractors for contingency and A&E services. The cost comparisons without the cost of the supplementary boilers are still substantially different.

A capital cost comparison between the contractors advanced simple-cycle gas turbines burning coal-derived residual fuel is shown in figure 5.3-17. Here, there are cost differences in every cost category. For this case UTC chose a design option using supplementary firing of the heat-recovery steam generator to yield a power-to-heat ratio of 0.333. By doing this, UTC needed a much smaller supplementary boiler to satisfy the site heat requirements. However, this does not explain the cost difference for the supplementary boiler (category 5), since a comparison of the costs on the basis of dollars per kilowatt thermal in the boiler still indicates considerable cost differences ($15.5/kW thermal for UTC, $74.8/kW thermal for GE). Costs without the supplementary boiler still differ greatly between the contractors.

A capital cost comparison of the three indirectly fired simple-cycle systems burning coal that were studied by UTC is shown in figure 5.3-18. The PFB system is the least expensive, followed by the gasifier system, with the AFB system the most expensive. These systems have much higher capital costs than the UTC advanced simple-cycle cases burning coal-derived residual fuel (fig. 5.3-17) because of the higher capital costs for coal and waste handling (category 1) and for the energy conversion system heat source or gasifier (category 2). Also, these systems are electrically less efficient than the liquid-fueled gas turbines, and this tends to make them more expensive on a dollars-per-kilowatt basis.

In figure 5.3-18 it is noted that the AFB system does not require a supplementary boiler to match the power-to-heat ratio of 0.25. As mentioned previously the simple-cycle AFB system has three design options, with varying amounts of process steam being raised in the AFB. One of these options happens to correspond to a system power-to-heat ratio of 0.25. For the PFB system supplementary heat is supplied by enlarging the PFB and adding steam tubes to it, analogous to what is done in the AFB system. However, the cost of the additional heat transfer area in the PFB is reported in category 5, whereas the cost of raising process steam in the AFB is reported in category 2 (heat source). For the gasifier case a separate, coal-fired boiler is used for supplementary heat requirements. The costs for supplementary heat are so small as compared with other cost categories that the comparison with and without the cost of supplementary heat does not change very much.

A capital cost comparison between GE's simple and recuperated open-cycle gas turbines is shown in figure 5.3-19. The higher capital cost for the recuperated system is due to the added cost of the recuperator.

A capital cost comparison between the contractors' steam-injected gas turbines burning coal-derived residual fuel is shown in figure 5.3-20. A

capital cost difference of more than a factor of 2 exists between the estimates. The cost differences occur in every cost category.

A capital cost comparison of UTC's coal-fired, steam-injected gas turbines is shown in figure 5.3-21. Here the capital costs are essentially the same for both systems and considerably higher than the capital costs for UTC's liquid-fueled, steam-injected gas turbine shown in figure 5.3-20.

5.3.2.4 Economics

The levelized annual operating cost saving versus incremental capital cost is shown in figures 5.3-22 to 5.3-31 for both contractors' open-cycle gas turbine systems matched with the nine representative industrial processes. Levelized annual operating cost saving is defined as the difference in levelized annual operating costs for fuel, electricity, and O&M between the cogeneration system and the noncogeneration case. In each figure the origin corresponds to the noncogeneration situation, where all required power is purchased and onsite steam is produced in a residual-fueled boiler. Since the power requirement varies considerably from process to process (table 4.4-1), the incremental capital cost and levelized operating cost saving are expressed per unit of site power required. As noted, not all of the cogeneration cases are sized to match the site power requirement. Also shown are lines of constant return on investment.

The results for both contractors' state-of-the-art simple-cycle gas turbines burning petroleum distillate fuel are shown in figure 5.3-22. The UTC systems are shown to reach a higher level of ROI because of the higher levelized annual operating cost saving. The incremental capital costs are generally the same for both contractors. Since the GE capital costs are shown to be larger than UTC's in figure 5.3-16, the fact that their incremental capital costs are the same indicates that for the noncogeneration cases GE's capital costs are higher than UTC's.

The incremental capital cost versus levelized annual operating cost saving for the GE state-of-the-art simple-cycle gas turbine burning petroleum residual fuel is shown in figure 5.3-23. The levelized annual operating cost saving is higher than that for the distillate-fueled cases shown in figure 5.3-22(a). This is due to the use of the less expensive residual fuel and results in generally higher ROI's for these cases.

The results for the advanced simple-cycle gas turbines burning coal-derived residual fuel are shown in figure 5.3-24. The UTC results reach a slightly higher range of ROI than the GE cases. The incremental capital costs, levelized annual operating cost savings, and the ranges of ROI are higher for both contractors than shown in figure 5.3-22 for the state-of-the-art simple-cycle cases. The incremental capital costs for the export cases are higher than those for the corresponding match-power cases since the onsite energy conversion system is larger. But because the operating saving in none of these cases is raised sufficiently in comparison with the capital cost increase, the ROI's of export cases are lower than those for the corresponding match-power cases.

The incremental capital cost versus levelized annual operating cost saving is shown for UTC coal-fired, simple-cycle gas turbines in figures 5.3-25 to

5.3-27. The ranges of ROI for the gasifier cases are slightly higher than the ranges achieved by the AFB and PFB systems. Even though the levelized annual operating cost savings are higher for the coal-fired systems than for the liquid-fueled gas turbines (fig. 5.3-24), the ROI's are lower because of the higher incremental capital costs for the coal-fired cases. For the AFB and PFB cases no results are shown for the petroleum process. The petroleum process requires most of its process heat in the form of hot gas (referred to by UTC as direct heat). A small portion of this direct-heat requirement is met by the gas turbine exhaust, with the remaining requirement being satisfied by supplementary fuel firing. In the noncogeneration case this direct-heat requirement is met by burning coal-derived residual fuel. For the cogeneration cases using AFB and PFB the supplementary direct-heat requirement was assumed by UTC to be met by burning coal. As a result, substantial levelized annual operating cost savings are realized by the switch to a less-expensive fuel, and not because of fuel savings due to cogeneration. These cost savings result in very high ROI's for the AFB and PFB gas turbines when matched to the petroleum process. Therefore these cases are not shown in figures 5.3-26 and 5.3-27 nor in the figures where the incremental capital cost and levelized annual operating saving are shown for the steam-injected gas turbines using AFB's and PFB's (figs. 5.3-30 and 5.3-31).

Results for GE's recuperated gas turbine burning coal-derived distillate fuel are shown in figure 5.3-28. The levelized annual operating cost savings are considerably less than that for the simple-cycle cases burning coal-derived residual fuel (fig. 5.3-24(a)) because of the higher cost of the distillate fuel. The incremental capital costs are higher than those for the simple-cycle cases because of the added cost of the recuperator. These two factors combine to contribute to the lower ROI range for the recuperated cases.

The incremental capital cost versus levelized annual operating cost saving is shown for steam-injected, simple-cycle gas turbines burning coal-derived residual fuel in figure 5.3-29. A higher range of ROI is achieved by the UTC cases than by the GE cases because of the higher levelized annual operating cost saving resulting from generally higher FESR's (fig. 5.3-12) and lower incremental capital costs (fig. 5.3-20). The range of ROI's is generally lower for the steam-injected cases in figure 5.3-29 than for the simple-cycle cases in figure 5.3-24.

The incremental capital cost versus levelized annual operating cost saving is shown for the UTC coal-fired, steam-injected gas turbines in figures 5.3-30 and 5.3-31. The AFB systems (fig. 5.3-31) have a higher range of ROI than the PFB systems (fig. 5.3-30). The AFB systems with high ROI have a matching strategy that results in power import in the cogeneration case. For these cases the AFB power system supplies only a very small fraction of the electrical requirements of the site (10 percent or less). This results in a relatively small incremental capital cost for the power system. At the same time a positive levelized annual operating cost saving is achieved (even in some cases where the fuel energy saving ratio is negative) because of the switch from residual fuel in the noncogeneration case to less expensive coal in the cogeneration case. Consequently the low incremental capital cost with power import and the positive levelized annual operating cost saving result in relatively high ROI's for these cases. For the PFB cases the import of power is not as attractive in terms of performance or economics; therefore UTC did not choose any import options for the PFB cases.

The other economic parameter used in CTAS to combine the effects of capital and operating cost is the percent saving in levelized annual energy cost, defined in section 4.3. In figures 5.3-32 and 5.3-33 the levelized annual energy cost saving ratios (LAECSR's) are shown for the liquid-fueled and coal-fired open-cycle gas turbines, respectively, when matched to the nine representative industrial processes. In part (a) of each figure only cases that do not involve export are included; in parts (b) all cases are included. In each part of the figures, when there is more than one matching strategy to choose from, the one with highest LAECSR is shown.

In spite of the higher capital cost the coal-fired systems in figure 5.3-33 have higher LAECSR's than the liquid-fueled systems shown in figure 5.3-32 because of the lower price of coal. This result differs from the comparison of ROI's between the coal-fired systems (figs. 5.3-25 to 5.3-27) and liquid-fueled systems (fig. 5.3-24(b)). That comparison indicated the advanced coal-derived-residual-fueled systems to have a higher range of ROI and hence to look economically more attractive. The state-of-the-art gas turbines and the advanced recuperated gas turbines, both burning coal-derived distillate fuel (fig. 5.3-32), have the lowest LAECSR's of all of the configurations because of the higher price of the distillate fuel.

In part (b) of both figures the LAECSR's are shown for cases including export of electricity. In figure 5.3-32(b) with only the exception of the advanced gas turbine burning coal-derived residual fuel, the results are the same as in part (a) for both contractors. Generally the cases including export have lower LAECSR's than those without. By including export excess electricity is generated and sold to a utility at 60 percent of the buying price to the industry. However, the increased capital cost component of the levelized annual operating cost and the increased cost of burning additional fuel in most cases more than offset the revenue from the sale of electricity and the higher fuel energy saving ratio. For the advanced systems burning coal-derived residual fuel the high FESR and the relatively lower amount of power exported (as compared with recuperated and steam-injected systems) results in some export cases with higher LAEC. Note that this differs from the economic results for these cases shown in figure 5.3-24, where generally the export cases result in lower ROI. In figure 5.3-33(b) similar results are shown for the coal-fired gas turbine systems. With the exception of a few advanced simple-cycle gas turbine cases with a coal gasifier, there is no advantage in LAECSR in exporting electricity. Unlike the liquid-fueled cases discussed previously, the coal gasifier cases look economically attractive in terms of LAECSR when exporting electricity and agree with the results shown in figure 5.3-25 for ROI. The export cases would look more attractive economically with a higher sell-back price of electricity.

In comparing the LAECSR's savings for some of the coal-fired systems in figure 5.3-33 to the FESR's in figure 5.3-13, it is seen that some cases that have relatively low fuel energy savings have relatively high levelized annual energy cost savings. This occurs in the case of several processes with low power-to-heat ratios when a match-power strategy is used such that a large supplementary boiler is needed in the cogeneration case. Because only a part of the process steam (or direct heat in the case of petroleum) is generated from the gas turbine waste heat, the fuel energy saving is low. But these results assume the use of residual fuel in the noncogeneration boiler, and both contractors assumed the use of coal to generate supplementary steam (or direct heat in the case of petroleum) when coal is used in the cogeneration case.

Thus, in such cases the operating cost saving is derived from the switch to less expensive fuel rather than from a saving of energy. Since the operating cost is generally the largest contribution to the LAEC, this results in the same effect in terms of LAEC. When the same fuel is assumed to be used in cogeneration and noncogeneration cases, this effect does not occur, but the relationship between LAECSR and FESR is still complicated by the effects of power-to-heat ratio, the matching strategy used, and the hours of operation per year. These effects and relationships between the parameters used in CTAS are discussed further in terms of some parametric cases in appendix D.

As noted previously, in some cases economic comparisons based on LAEC can produce different results from those based on ROI. A comparison based on ROI indicates that the advanced gas turbine burning coal-derived residual fuel is economically more attractive than the coal-fired gas turbines. However, the comparison based on LAEC shows the coal-fired systems to be more attractive economically. Likewise, a comparison of results based on ROI indicates that sizing the advanced gas turbine that uses coal-derived residual fuel so that electricity is exported results in lower ROI, yet a comparison based on LAEC indicates that export of electricity results in higher LAEC when the energy conversion systems are matched with industries that have low power-to-heat ratios. Comparisons of the other gas turbine configurations using ROI and LAEC are in general agreement.

5.3.2.5 Relative National-Basis Fuel Saving

Fuel savings accumulated to a national basis are shown as a function of hurdle ROI in figures 5.3-34 to 5.3-43. The procedure used to calculate these curves is described in section 4.4. It was assumed for each system that it would be 100 percent implemented in new-capacity additions or retirement replacements between 1985 and 1990 in each process where the results yield an ROI greater than the hurdle rate shown. Results were calculated for the GE systems using 40 of the processes they studied and for the UTC systems using 26 processes. No extrapolation beyond these processes was done. These figures are intended to illustrate the comparative potential saving versus the ROI requirement, not as an illustration of the absolute magnitude of the savings.

The results for the state-of-the art simple-cycle gas turbine burning petroleum distillate fuel are shown in figure 5.3-34. Only cogeneration strategies that do not involve export of power from an individual plant site are included. The GE results extend to a slightly higher range of ROI than the UTC results. For both the GE and UTC cases the potential national fuel saving if an ROI greater than 10 percent were required is about 75 to 80 percent of the saving if no hurdle ROI were applied. Only one GE case exceeds 20 percent ROI, and no UTC cases do so.

The results for the state-of-the-art systems burning petroleum distillate fuel when export of power from individual plant sites is allowed are shown in figure 5.3-35. In both parts of the figure the potential national fuel saving shown for low ROI hurdle rates is slightly higher than that shown in figure 5.3-34, which does not include power export. For the GE case the inclusion of power export does not change the range of ROI's achieved by the system nor the general shape of the curve. For the UTC cases the range of ROI increases dramatically over that for the cases where power export is excluded. However,

it should be noted that the potential national fuel saving for an ROI of 10 percent or greater is much less for the case where power export is included.

The potential national fuel saving versus hurdle ROI is shown in figure 5.3-36 for GE's state-of-the-art simple-cycle gas turbine system burning petroleum residual fuel, with no export of power from the plant site being considered. The residual-fueled cases achieve higher levels of potential fuel energy saving and ROI than GE's state-of-the-art system burning distillate fuel (fig. 5.3-34(a)), Although the fuel energy saving ratios for specific plant sites are lower for the state-of-the-art residual-fueled cases (fig. 5.3-12(a)), the use of the less expensive residual fuel results in many more industries having positive ROI, and this increases the potential national fuel saving. The use of the less expensive fuel also increases the range of ROI.

The results for the advanced simple-cycle gas turbines burning coal-derived residual fuel are shown for both contractors in figure 5.3-37 with no export of power from the plant site. The UTC cases achieve a higher range of ROI, but the GE cases achieve higher potential fuel savings at lower ROI levels. For both contractors the advanced simple-cycle gas turbine system achieves a higher range of ROI and higher potential national fuel saving than the state-of-the-art systems (figs. 5.3-34 to 5.3-36). What is especially significant are the relative amounts of potential fuel saving at higher hurdle ROI's as compared with the state-of-the-art systems. For the advanced systems, essentially all of the potential fuel savings occur at ROI's greater than 10 percent, and most of the savings are at ROI's greater than 20 percent. This means that the advanced simple-cycle gas turbines burning coal-derived residual fuel would be implemented in more industries and with greater fuel saving benefits than the state-of-the-art systems burning petroleum fuels.

Large ROI values are shown for the UTC corrugated paper and boxboard processes in figure 5.3-37(b). Both of these industries produce a byproduct black-liquor fuel, as mentioned previously. Also, both industries have relatively low power-to-heat ratios. Because of the low power-to-heat ratio a large amount of fuel must be burned in a supplementary boiler to supply a portion of the required process heat when a match-power strategy is used. Now, the gas turbine cannot use the byproduct black-liquor fuel, but the supplementary boiler can use this fuel. Thus high operating cost savings result from not buying fuel for the supplementary boiler, and this causes the high values of ROI for these two industries.

The potential national fuel saving versus hurdle ROI is shown in figures 5.3-38 to 5.3-40 for the advanced coal-fired, simple-cycle gas turbines studied by UTC. For the PFB (fig. 5.3-38) and AFB (fig. 5.3-39) systems large ROI's are shown for the ethylene, styrene, and petroleum refining processes. These three processes require a considerable amount of process heat, which is only partly supplied by the gas turbine. Thus a supplementary furnace or boiler is required. In the noncogeneration case coal-derived residual fuel is used to produce the required process heat. However, in the cogeneration cases with AFB and PFB, UTC assumes the use of coal in the supplementary boiler or furnace. Thus substantial operating cost savings occur because of the switch from residual fuel to less expensive coal, and this results in the high ROI's shown. If the results for these three industries are ignored for the PFB and AFB systems, the results for these systems (and those for the coal gasifier system (fig. 5.3-40) would all be about the same. Also, at the same ROI's,

the coal-fired systems have lower potential fuel energy savings than the advanced simple-cycle gas turbine using coal-derived residual fuel (fig. 5.3-37(b)). If we ignore the results for the three industries mentioned previously with the AFB and PFB systems, the coal-fired systems have lower potential fuel savings and ROI's than the systems burning coal-derived residual fuel.

The results for the advanced steam-injected, simple-cycle gas turbine burning coal-derived residual fuel are shown in figure 5.3-41 for both contractors. There is a substantial difference between the contractors' results, with the UTC results indicating much better potential fuel savings and ROI's. There are two reasons for this. First, the UTC design options chosen for the liquid-fueled systems were better matches for most industries in terms of fuel energy saving than the GE systems (figs. 5.3-10 and 5.3-12). Second, the GE estimates of capital costs are considerably higher than those of UTC (fig. 5.3-20), and this along with lower FESR contributes to less attractive economic results. Thus the results for the GE steam-injected systems are considerably lower than those for the GE advanced simple-cycle gas turbines (fig. 5.3-37(a)). For UTC, although the potential fuel savings and range of ROI are slightly lower for their steam-injected cases than for their advanced simple-cycle cases (fig. 5.3-37(b)), they are somewhat higher than those for to the state-of-the-art systems burning petroleum distillate fuel (fig. 5.3-34(b)).

The potential national fuel saving versus hurdle ROI is shown in figures 5.3-42 and 5.3-43 for the coal-fired, steam-injected gas turbines studied by UTC. As mentioned previously for the advanced simple-cycle cases with AFB and PFB, the high ROI results for ethylene, styrene, and petroleum refining are a result of switching from a residual fuel in the noncogeneration case to less expensive coal in the cogeneration case and not as a result of more efficient use of fuel energy from cogeneration. When the results for these three industries in figures 5.3-42 and 5.3-43 are ignored, the potential fuel savings for the AFB systems (fig. 5.3-42) are very small, with the potential fuel savings for the PFB systems (fig. 5.3-43) being higher at low values of ROI. Both show lower ranges of ROI and potential fuel saving than the steam-injected gas turbine burning coal-derived residual fuel (fig. 5.3-41(b)).

5.3.3 Summary

The ranges of results achieved by the liquid-fueled and coal-fired open-cycle gas turbine systems, respectively, are shown in tables 5.3-3 and 5.3-4 for a subset of nine representative industrial processes. For each parameter the industrial process that yielded the maximum value is also indicated. Results are shown for cases with and without power export from the cogeneration site.

Results for the liquid-fueled systems are shown in table 5.3-3. For GE the maximum fuel energy saving ratios (FESR) are attained with the advanced simple-cycle system burning coal-derived residual fuel when export of power is not considered. The lowest FESR's for GE occur with the steam-injected gas turbine burning coal-derived residual fuel. For most of the GE systems without export the highest FESR occurs when the system is matched to the newsprint process. The GE newsprint process requires a power-to-heat ratio that closely

matches the ratio produced by those GE gas turbine systems at the required steam temperature (366° F). For the GE steam-injected gas turbines the chlorine process provided the closest power-to-heat ratio match to that produced by the energy conversion system. For the UTC cases without export the maximum FESR value is attained by the steam-injected gas turbine burning coal-derived residual fuel. The state-of-the-art simple-cycle gas turbine burning petroleum distillate fuel has the lowest FESR. For all of the UTC liquid-fueled configurations without export, the highest FESR's are attained with the chlorine industry. In UTC's chlorine industry some byproduct hydrogen fuel is available for use in the energy conversion system. The use of this hydrogen fuel reduces the amount of purchased fuel and thus increases the FESR.

The emissions saving ratios (EMSR) for the distillate-fueled systems are generally higher than those for residual fueled systems. For the advanced simple-cycle gas turbines burning coal-derived residual fuel there is a substantial difference in EMSR between the contractors. As mentioned previously, there is a large difference in the NO_x emissions between the contractors, and this resultes in the difference in EMSR (table 5.3-2).

The levelized annual energy cost saving ratio (LAECSR) is largest for the GE advanced simple-cycle system and for the UTC steam-injected gas turbine, both burning coal-derived residual fuel. The residual-fueled cases generally have higher LAEC than the distillate-fueled cases because of the lower price of residual fuel.

For each contractor the returns on investment (ROI) for the coal-derived-residual-fueled cases are generally larger than the ROI's for the distillate-fueled cases. As shown, for both contractors the highest ROI's occur in the chlorine industry for all of the liquid-fueled gas turbine configurations. For both the GE and UTC systems generally the highest ROI's with chlorine occur when cogeneration matching strategies that require import of electricity are used (figs. 5.3-22 and 5.3-31). For the GE systems the power-to-heat ratio of the chlorine industry is approximately 1.5. When the match-heat strategy with power import is used, fairly good FESR values are attained for the GE configurations (fig. 5.3-12). Also, the energy conversion system capital cost is lower because the match-heat strategy with import is used. The fairly good FESR with low capital cost results in high ROI for the GE liquid-fueled systems. Likewise, the use of an import strategy with low capital cost contributes to high ROI's for the UTC systems. In addition, UTC assumed the use of byproduct hydrogen fuel, which reduces the amount of purchased fuel and therefore contributes to the higher UTC ROI values. GE did not assume any byproduct fuel for the chlorine process that they studied.

Results are shown for the liquid-fueled gas turbine systems when electricity is exported from the cogeneration site in table 5.3-3(b). For most cases power export results in slightly higher values of FESR. Generally, for the GE cases the highest FESR with power export occurs with the malt beverage and meat packing processes. These two processes require process heat in the form of 250° F steam and hot water. Because of the relatively low temperature of the process heat requirement, more heat can be recovered from the gas turbine exhaust for most of the configurations. Thus with the match-heat strategy and power export the slightly higher recovery of the exhaust heat because of the low process temperature requirement results in slightly higher values of FESR. With the exception of the steam-injected gas turbine

the UTC configurations achieve their highest FESR when export is considered with the writing paper process. As shown in figure 5.3-12(b) a number of other industries have essentially the same FESR as the writing paper process with the values differing slightly because of differences in auxiliary electricity and steam requirements. The steam-injected gas turbine achieves its highest FESR in the chlorine process, as it does when power export is not considered.

For the state-of-the-art gas turbine systems the values for EMSR increase slightly when power export is considered, whereas those for the advanced systems remain the same as shown in table 5.3-3(a) without power export. For the UTC advanced systems the maximum EMSR occurs in the chlorine industry when an import strategy is used and thus does not change when export is allowed. For GE the maximum EMSR occurs in the writing paper process (bleached Kraft). As shown in figure 5.3-14(b) the EMSR's for many of GE's industries increase when export is allowed. However, the maximum EMSR, which occurs in the writing paper industry, does not increase, and thus the range of EMSR remains the same.

There is no increase in LAEC when export of electricity is included, since the higher capital cost of the system when exporting electricity more than offsets the revenue from its sale. A higher sell-back price for the excess power (60 percent of the utility selling price was assumed) would significantly improve the export cases. Likewise, the level of ROI does not increase when export of electricity is included. As mentioned previously the maximum ROI's occur for both contractors in the chlorine industry when matching strategies are used that result in the import of electricity. Thus the maximum ROI's do not change when power export is included.

The range of results is shown in table 5.3-4 for the coal-fired systems matched to the nine representative processes. The highest FESR results for the simple-cycle systems are achieved in the newsprint and writing paper processes both with and without power export. As mentioned previously the use of the byproduct fuel from these two processes in the energy conversion system or the supplementary boiler results in the large values of FESR shown. For the PFB steam-injected gas turbine system without power export the chlorine process offers the best match in terms of the power-to-heat ratio. The AFB steam-injected gas turbine match with the meat packing industry results in the best FESR. Meat packing requires some of its process heat in the form of hot water. As shown in figure 5.3-11 the potential fuel saving for the AFB steam-injected gas turbine increases substantially when hot water is the form of heat required. The EMSR values reflect the trends shown for FESR. Since no emissions were assumed for the burning of the byproduct fuels, the systems matched with the newsprint and writing paper industries have EMSR's comparable to those for the relatively cleaner coal-derived liquid fuels (table 5.3-3).

The LAEC values shown for the coal-fired systems are somewhat higher than the values shown for the liquid-fueled systems in table 5.3-3. In the case of the writing paper process the use of the byproduct black-liquor fuel in the energy conversion system contributed to the higher LAEC. Also, for the results shown the noncogeneration onsite boiler was assumed to use residual fuel. UTC assumed that in coal-fired cogeneration systems any required supplementary boiler would use coal. Thus in low-power-to-heat-ratio processes the LAEC saving is high not only because of a saving in fuel energy due to cogeneration, but also because of a switch to coal rather than the more expensive coal-derived residual fuel in the onsite boiler. As mentioned previously the UTC

petroleum-refining process requires a considerable amount of direct heat, and the large LAEC is a result of switching the fuel from residual to coal to supply the requirement. Also, for this reason the petroleum-refining process had the highest values of ROI for the coal-fired systems, except for the simple-cycle gasifier system. For this system UTC did not assume a switch to coal to supply the direct-heat requirement, and thus the chlorine industry has the highest ROI. The industry with the highest ROI for the PFB and AFB coal-fired systems is chlorine (figs. 5.3-26 and 5.3-27). For the PFB steam-injected gas turbine (fig. 5.3-30) the highest ROI occurs in the writing paper process. For the AFB steam-injected gas turbine (fig. 5.3-31) the highest ROI occurs in the alumina process. The results for the petroleum-refining process are not shown in these figures since the high ROI's are due to the switch in fuel and not to exceptional cogeneration performance.

As shown in figure 5.3-4(b) there is generally no substantial increase in the performance or economic parameters for the coal-fired systems when power export is considered. Although the FESR improves for those industries with low power-to-heat ratios (fig. 5.3-13(b)), the range of FESR's does not increase. Likewise, as mentioned earlier for the liquid-fueled cases, the economic parameters do not improve with power export because of increased capital cost and the 60 percent sell-back price of electricity from the cogeneration site.

TABLE 5.3-1. - ENERGY CONVERSION SYSTEM PARAMETERS AND CONFIGURATIONS STUDIED FOR OPEN-CYCLE GAS TURBINE SYSTEMS

Parameter	General Electric	United Technologies Corp.
Simple cycle, state of the art		
Distillate fuel:		
Turbine inlet temperature, °F/pressure ratio (PR)	2000/10	2000/10, 12, 14
Cooling medium	Air	Air
Supplementary firing	No	Yes(PR=14)
Residual fuel:		
Turbine inlet temperature, °F/pressure ratio	1750/10	---------------
Cooling medium	Air	---------------
Supplementary firing	No	---------------
Simple cycle, advanced		
Residual fuel:		
Turbine inlet temperature, °F/pressure ratio	2200/8, 12, 16; 2600/16	2500/14, 16, 18
Cooling medium	Air at 2200 °F; water at 2600 °F	Air
Supplementary firing	No	Yes(PR=18)
Coal-fired PFB:		
Bed temperature, °F	-----------------------	1650
Turbine inlet temperature, °F/pressure ratio	-----------------------	1600/6, 8, 10
Cooling medium	-----------------------	None
Coal-fired AFB:		
Bed temperature, °F	-----------------------	1600
Turbine inlet temperature, °F/pressure ratio	-----------------------	1500/10
Cooling medium	-----------------------	None
Integrated coal gasifier:		
Gasifer type	-----------------------	Entrained bed
Cleanup type	-----------------------	Cold gas
Turbine inlet temperature, °F/pressure ratio	-----------------------	2400/17; 2500/18
Cooling medium	-----------------------	Air
Recuperated cycle		
Fuel	Distillate	---------------
Turbine inlet temperature, °F/pressure ratio	2200/8, 12, 16; 2600/8, 12, 16	---------------
Recuperator effectiveness	0.60; 0.85	---------------
Cooling medium	Air at 2200 °F; water at 2600 °F	---------------
Steam-injected simple cycle		
Residual fuel:		
Turbine inlet temperaure, °F/pressure ratio	2200/16	2500/18
Cooling medium	Air	Air
Steam/air ratio	0.1(superheated steam); 0.1(saturated steam); 0.15(superheated steam)	0.05; 0.1
Coal-fired AFB:		
Bed temperature, °F	-----------------------	1600
Turbine inlet temperature, °F/pressure ratio	-----------------------	1500/10
Cooling medium	-----------------------	None
Steam/air ratio		
Coal-fired PFB:		
Bed temperature, °F	-----------------------	1650
Turbine inlet temperature, °F/pressure ratio	-----------------------	1600/10
Cooling medium	-----------------------	None
Steam/air ratio	-----------------------	0.05; 0.1

TABLE 5.3-2. - EMISSIONS FOR OPEN-CYCLE GAS TURBINE SYSTEMS

(a) Liquid-fueled systems

Pollutant	Petroleum distillate		Petroleum residual		Coal-derived residual	
	GE	UTC	GE	UTC	GE	UTC
	Emissions, lb/10^6 Btu					
Oxides of sulfur	0.52	0.52	0.75	0.76	0.8	0.82
Oxides of nitrogen	.4	.4	.05	.5	1.2	.5
Particulates	.0	.0	.016	.03	.153	.1
Total atmospheric emissions	.92	.92	1.266	1.29	2.153	1.42

(b) Coal-fired (UTC only)

Pollutant	Pressurized fluidized bed	Gasifier	Atmospheric fluidized bed
	Emissions, lb/10^6 Btu		
Oxides of sulfur	1.2	0.82	1.2
Oxides of nitrogen	.2	.05	.2
Particulates	.001	0	.1
Total atmospheric emissions	1.401	1.32	1.5

TABLE 5.3-3. - RANGE OF RESULTS FOR LIQUID-FUELED OPEN-CYCLE GAS TURBINE SYSTEMS USED WITH NINE REPRESENTATIVE INDUSTRIES

(a) No power export allowed

Energy conversion system subgroup	Contractor	Fuel energy saving ratio, FESR	Industry with maximum FESR	Emissions saving ratio, EMSR	Industry with maximum EMSR	Levelized annual energy cost, LAEC	Industry with maximum LAEC	Return on investment ROI, percent	Industry with maximum ROI
State-of-the art simple cycle/petroleum	GE(distillate)	10.7-30.3	Newsprint	22-50	Writing paper	Negative to 5.8	Newsprint	0-20	Chlorine
	GE(residual)	89.5-27.2	Newsprint	18-41	Writing paper	Negative to 15.5	Newsprint	0-27	Chlorine
	UTC(distillate)	Negative to 30.7	Chlorine	8.1-65.5	Chlorine	Negative to 13.2	Chlorine	0-32.9	Chlorine
Advanced simple cycle coal-derived residual	GE	11.4-31.8	Newsprint	5-22	Writing paper	Negative to 21.0	Newsprint	0-34	Chlorine
	UTC	3.9-35.4	Chlorine	7.2-55.8	Chlorine	Negative to 25.5	Chlorine	14-41.4	Chlorine
Recuperated open cycle/coal-derived distillate	GE	9.0-28.6	Newsprint	33-53	Writing paper	Negative to 7.6	Chlorine	0-15	Chlorine
Steam-injected simple cycle coal-derived residual	GE	11.0-22.8	Chlorine	3-12	Writing paper	Negative to 11.5	Chlorine	0-17	Chlorine
	UTC	4.3-37.2	Chlorine	5.6-57.1	Chlorine	Negative to 27.6	Chlorine	3.4-42.6	Chlorine

(b) Power export allowed

Energy conversion system subgroup	Contractor	Fuel energy saving ratio, FESR	Industry with maximum FESR	Emissions saving ratio, EMSR	Industry with maximum EMSR	Levelized annual energy cost, LAEC	Industry with maximum LAEC	Return on investment ROI, percent	Industry with maximum ROI
State-of-the art simple cycle/petroleum	GE(distillate)	10.7-32.1	Malt beverage; meat packing	22-62	Writing paper	Negative to 6.5	Newsprint	0-20	Chlorine
	GE(residual)	8.5-30.6	Malt beverage; meat packing	18-46	Writing paper	Negative to 16.5	Newsprint	0-27	Chlorine
	UTC(distillate)	Negative to 33.8	Writing paper	8.1-66.0	Writing paper	Negative to 13.2	Chlorine	0-32.9	Chlorine
Advanced simple cycle/coal-derived residual	GE	11.4-33.7	Malt beverage; meat packing	5-22	Writing paper	Negative to 22.6	Newsprint	0-34	Chlorine
	UTC	3.9-37.3	Writing paper	7.2-55.8	Chlorine	Negative to 25.5	Chlorine	12.9-41.4	Chlorine
Recuperated open cycle/coal-derived distillate	GE	9.0-36.2	Malt beverage; meat packing	33-53	Writing paper	Negative to 7.6	Chlorine	0-15	Chlorine
Steam-injected simple cycle coal-derived residual	GE	11-22.8	Malt beverage; writing paper; meat packing; newsprint; chlorine	3-12	Writing paper	Negative to 11.5	Chlorine	0-17	Chlorine
	UTC	4.3-37.2	Chlorine	5.6-57.1	Chlorine	Negative to 27.6	Chlorine	0-42.6	Chlorine

TABLE 5.3-4. - RANGE OF RESULTS FOR COAL-FIRED OPEN-CYCLE GAS TURBINE SYSTEMS USED WITH NINE REPRESENTATIVE INDUSTRIES

[Contractor, United Technologies Corp.]

(a) No power export allowed

Subgroup	Fuel energy saving ratio, FESR	Industry with maximum FESR	Emission saving ratio, EMSR	Industry with maximum EMSR	Levelized annual energy cost, LAEC	Industry with maximum LAEC	Return on invest-ment, ROI, percent	Industry with maximum ROI
Simple cycle								
With PFB	Negative to 33.7	Newsprint	5-51.3	Newsprint	Negative to 36.2	Petroleum	6.1-49.8	Petroleum
With AFB	Negative to 44.3	Writing paper	Negative to 53.6	Writing paper	Negative to 37.6	Writing paper	0-41.7	Petroleum
With gasifier	Negative to 32.7	Writing paper	Negative to 49.9	Writing paper	Negative to 37.4	Writing paper	0-22.8	Chlorine
Steam-injected simple cycle								
With PFB	Negative to 14.6	Chlorine	3.4-38.7	Chlorine	Negative to 35.1	Petroleum	0-50	Petroleum
With AFB	Negative to 19.5	Meat Packing	Negative to 23.5	Meat packing	Negative to 36.4	Petroleum	0-50	Petroleum

(b) Power export allowed

Subgroup	Fuel energy saving ratio, FESR	Industry with maximum FESR	Emission saving ratio, EMSR	Industry with maximum EMSR	Levelized annual energy cost, LAEC	Industry with maximum LAEC	Return on invest-ment, ROI, percent	Industry with maximum ROI
Simple cycle								
With PFB	Negative to 33.7	Newsprint	5-51.3	Newsprint	Negative to 37.2	Petroleum	5.5-49.8	Petroleum
With AFB	Negative to 44.3	Writing paper	Negative to 53.6	Writing paper	Negative to 37.6	Writing paper	0-41.7	Petroleum
With gasifier	Negative to 32.7	Writing paper	Negative to 49.9	Writing paper	Negative to 38.4	Writing paper	0-22.8	Chlorine
Steam-injected simple cylce								
With PFB	Negative to 15.8	Petroleum	3.4-38.7	Chlorine	Negative to 35.1	Petroleum	0-50	Petroleum
With AFB	Negative to 12.7	Petroleum	Negative to 29.3	Meat packing	Negative to 36.4	Petroleum	0-50	Petroleum

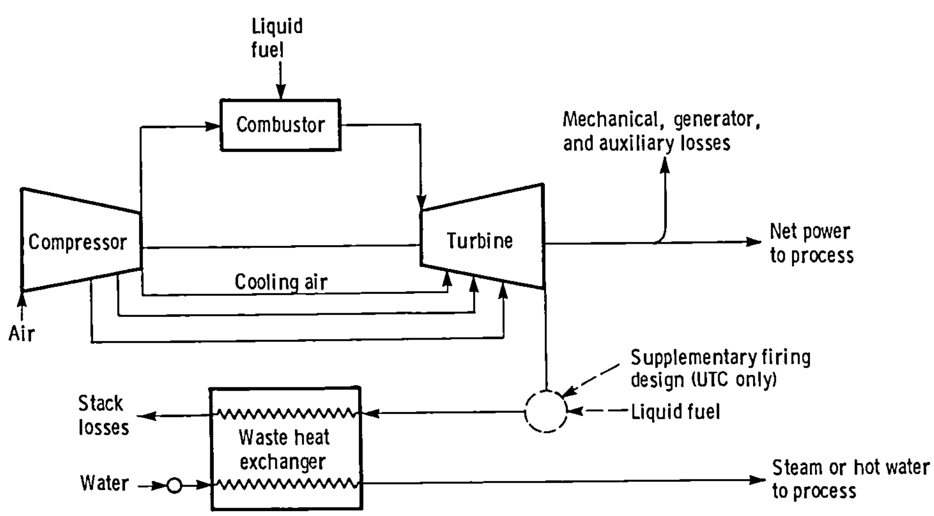
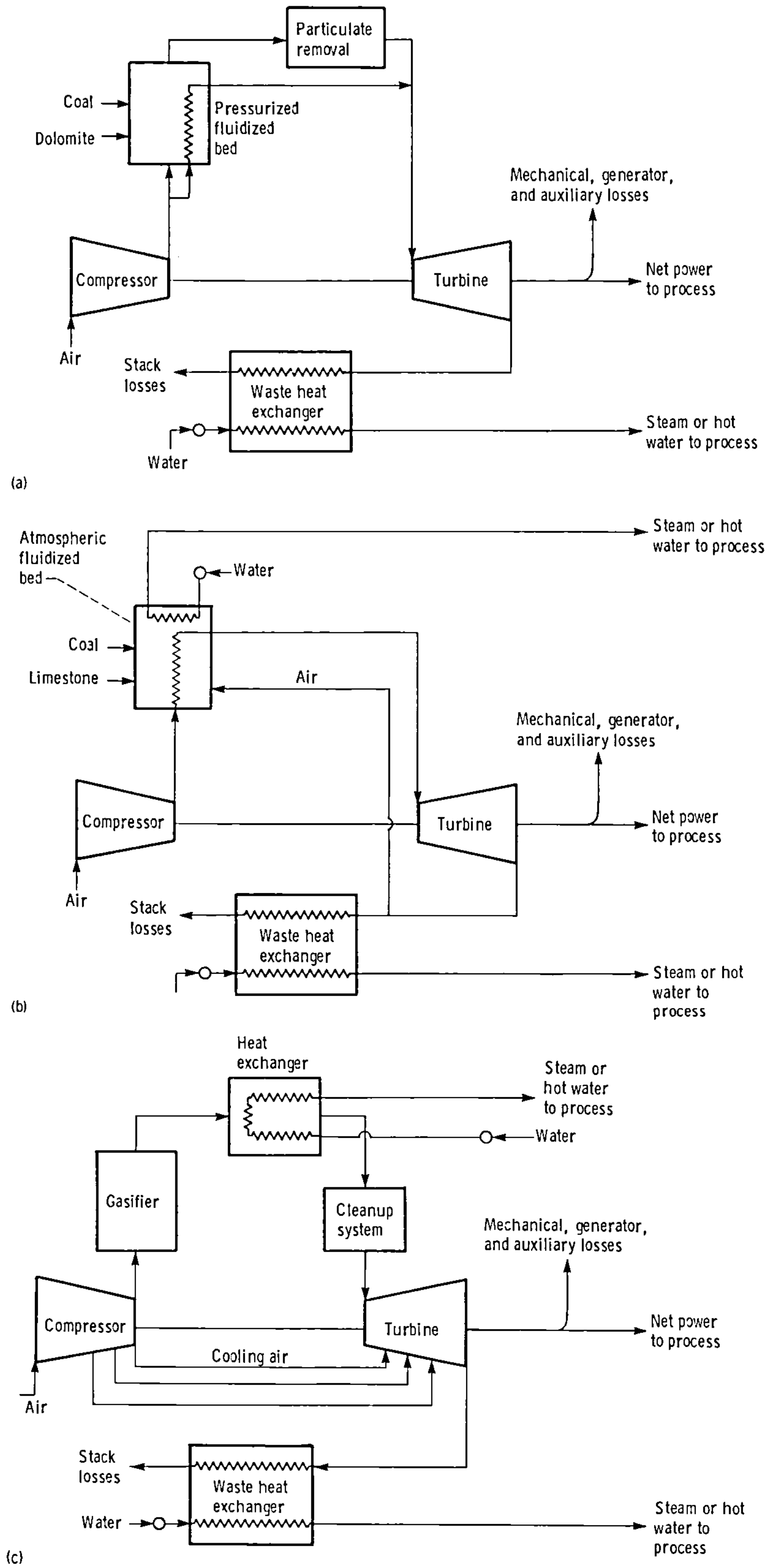


Figure 5.3-1. - Schematic of liquid-fueled open-cycle gas turbine system (typical of both contractors).



(a) Pressurized fluidized bed.
(b) Atmospheric fluidized bed.
(c) Integrated gasifier.

Figure 5.3-2. - Schematic for UTC externally fired open-cycle gas turbines burning coal.

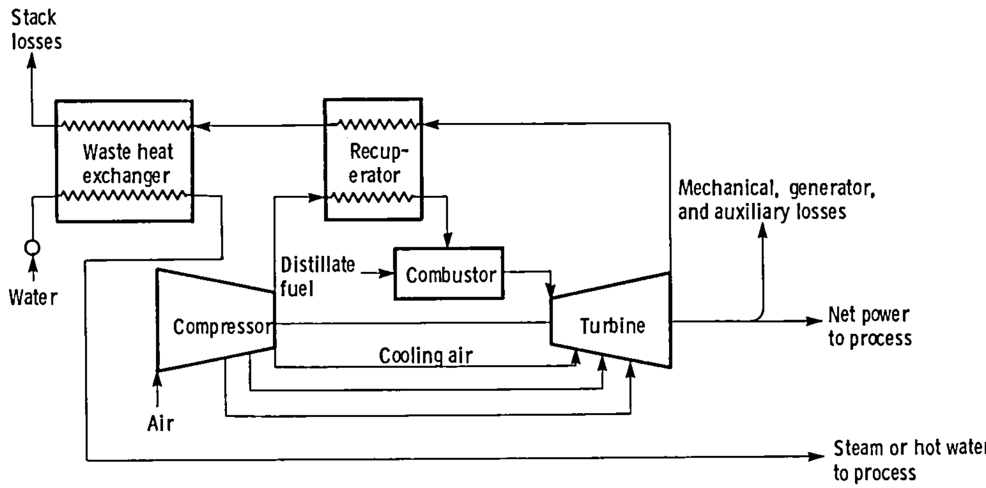


Figure 5.3-3. - Schematic of GE's recuperated, open-cycle gas turbine system.

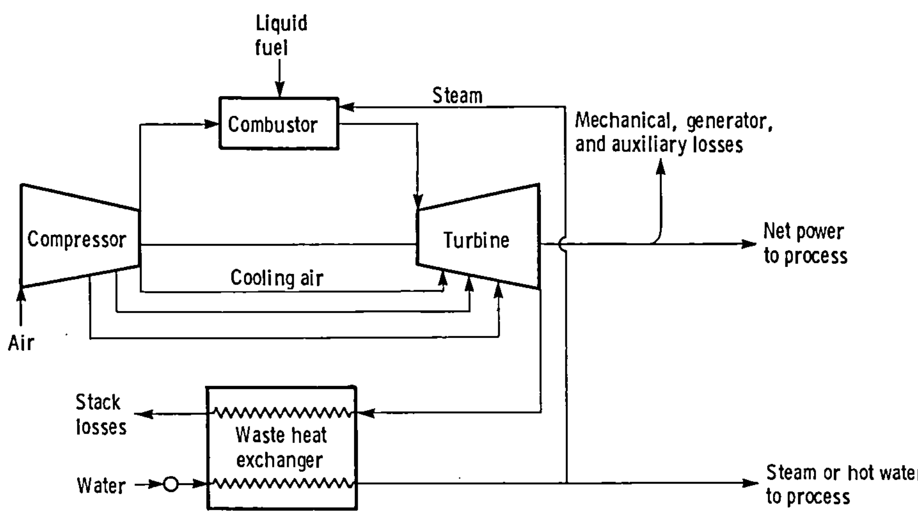
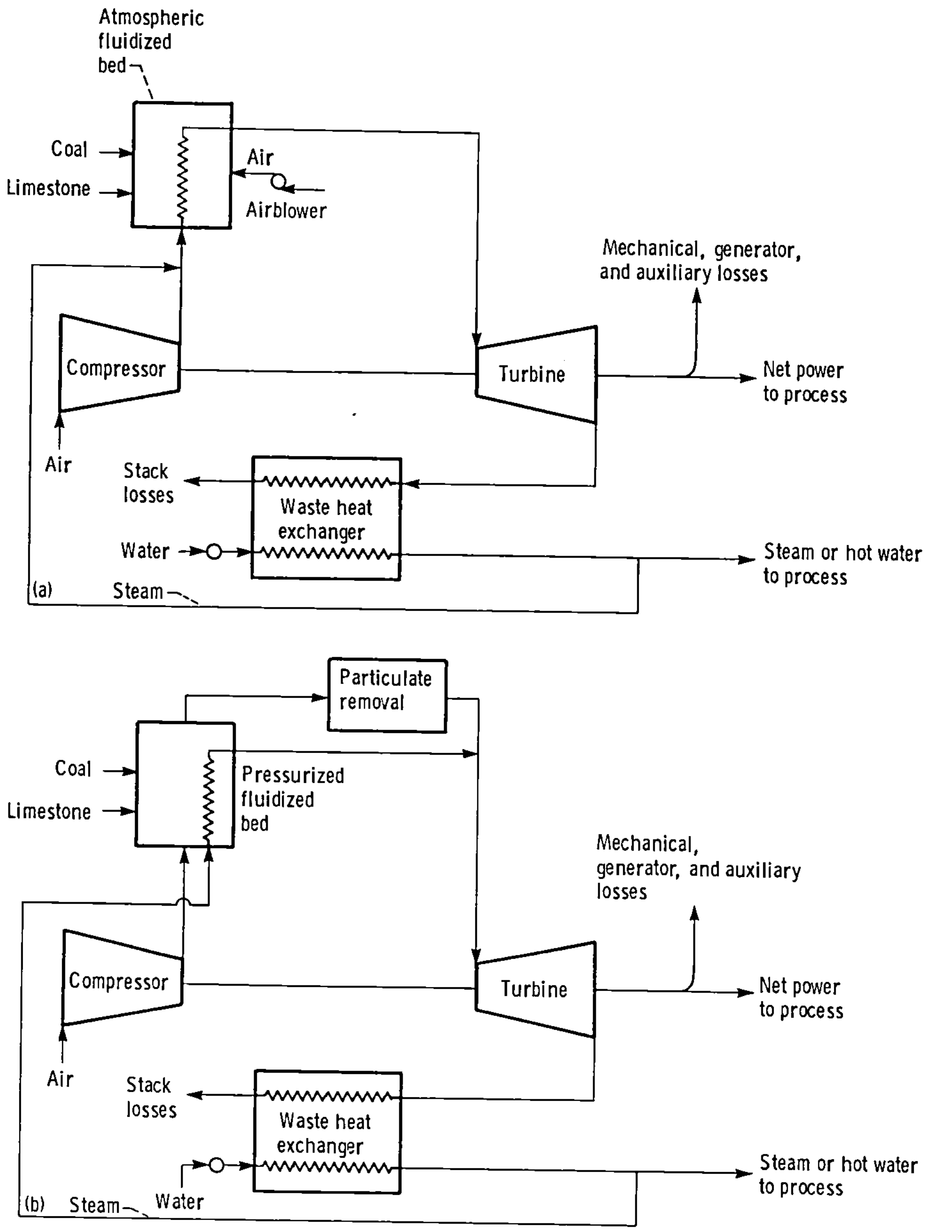


Figure 5.3-4 - Schematic of liquid-fueled, steam-injected, open-cycle gas turbine (typical of both contractors.



(a) Atmospheric fluidized bed.
(b) Pressurized fluidized bed.

Figure 5.3-5. - Schematic of UTC's coal-fired, steam-injected, open-cycle gas turbine system.

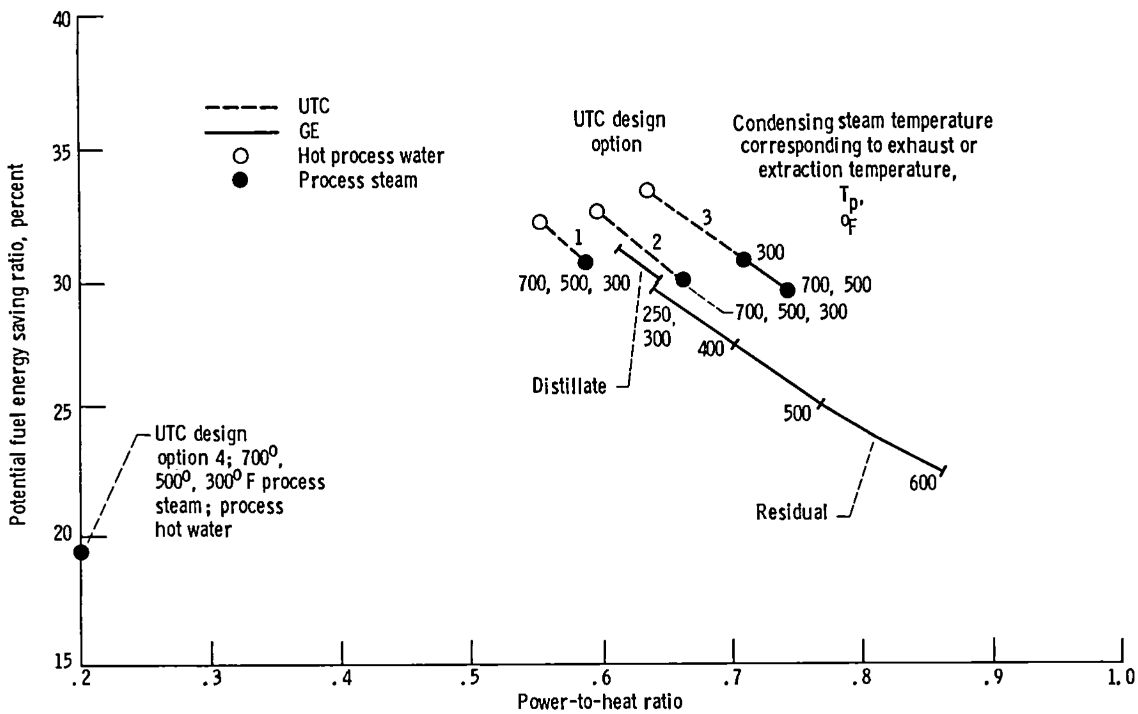


Figure 5.3-6. - Potential fuel energy savings for state-of-the-art simple-cycle gas turbine systems.

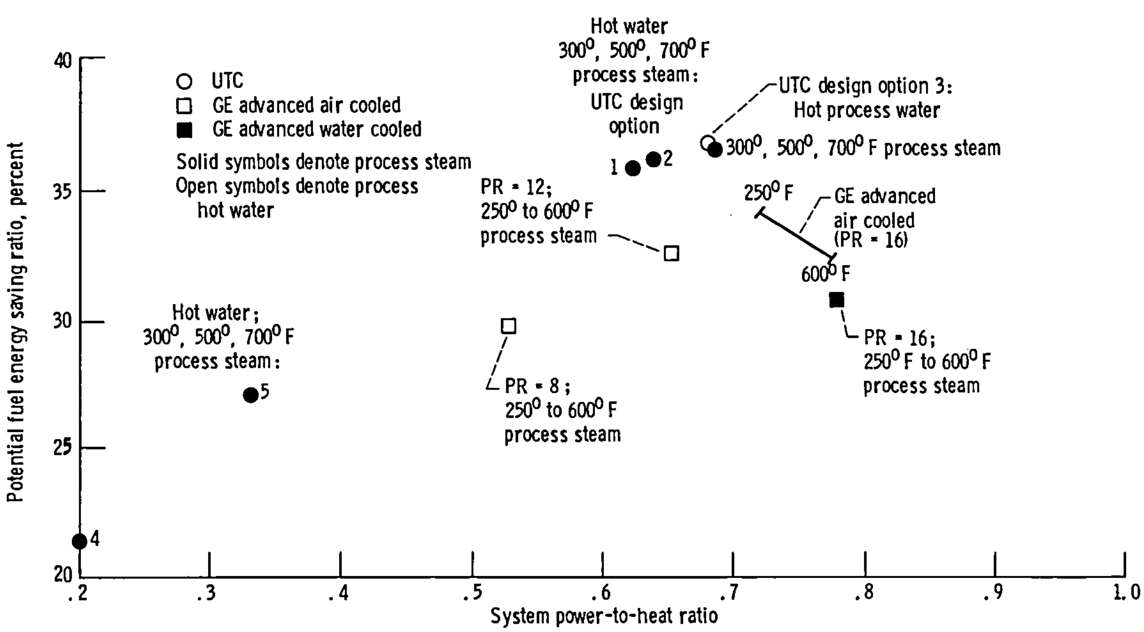


Figure 5.3-7. - Potential fuel energy savings for advanced simple-cycle gas turbine/coal-derived residual systems.

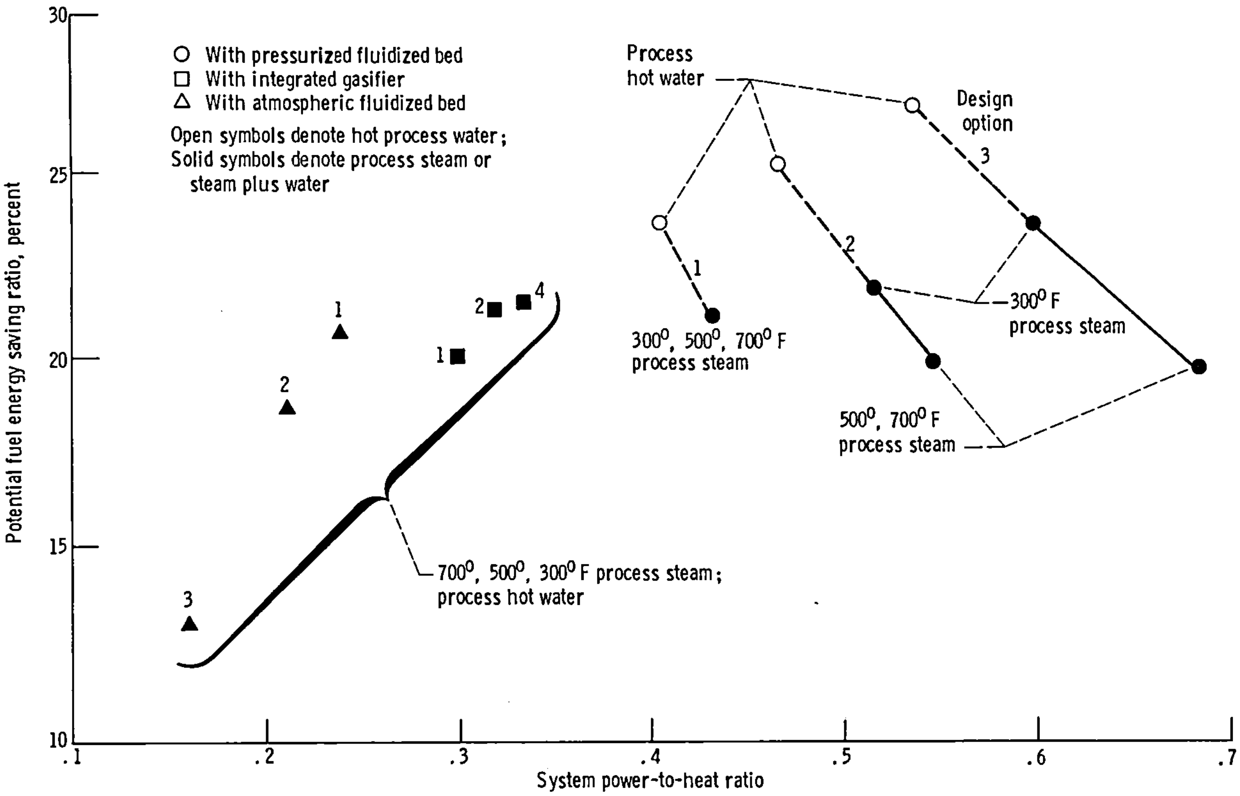


Figure 5.3-8. - Potential fuel energy savings for UTC's advanced coal-fired simple-cycle gas turbine systems.

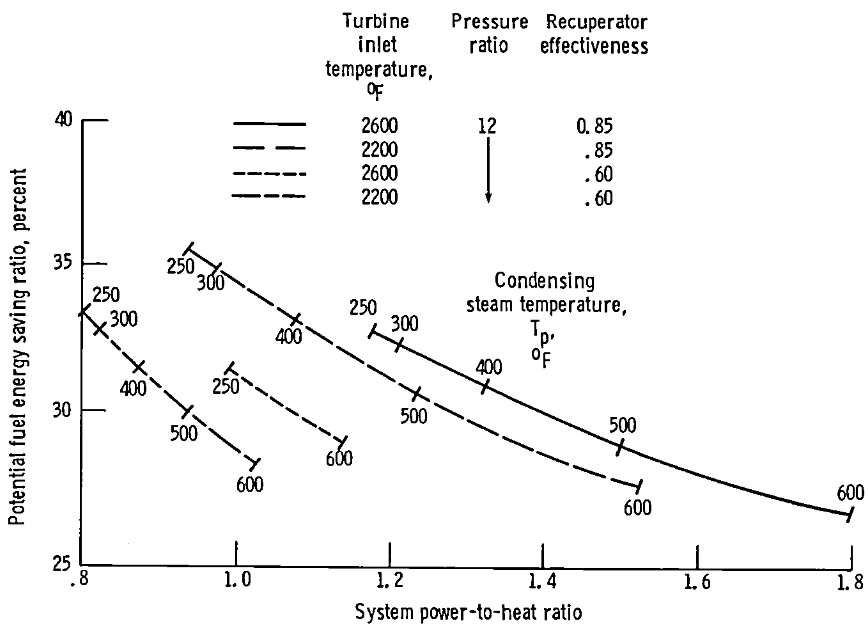


Figure 5.3-9. - Potential fuel energy savings of GE's advanced recuperated gas turbine system.

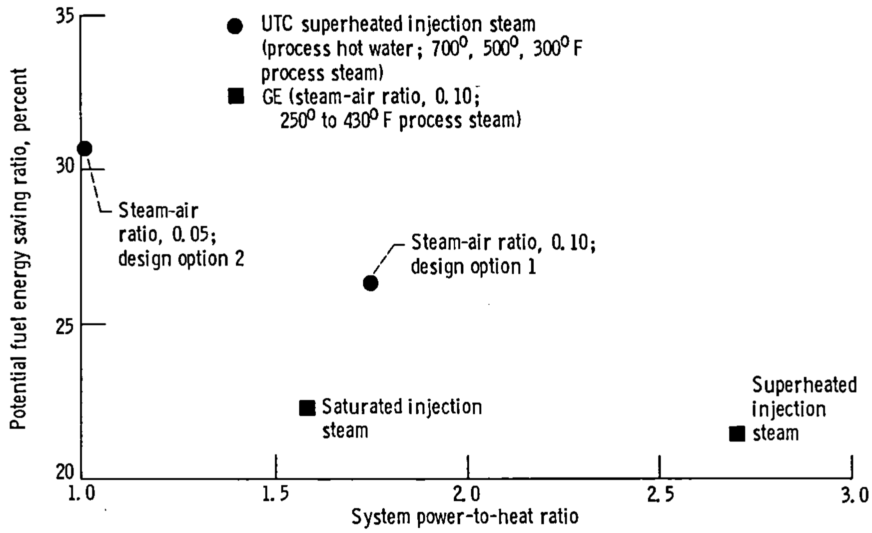


Figure 5.3-10. - Potential fuel energy savings for advanced steam-injected, simple-cycle gas turbine/coal-derived residual systems.

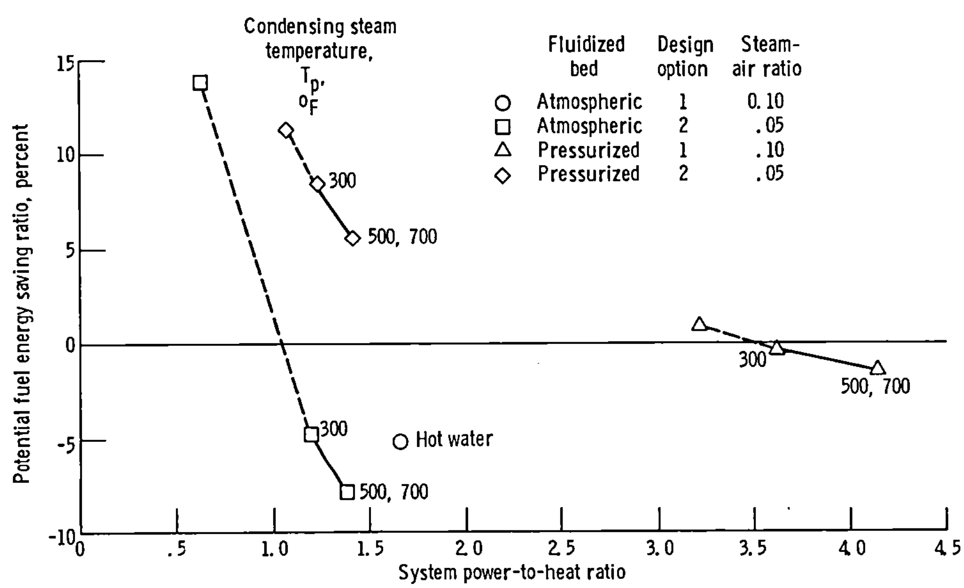
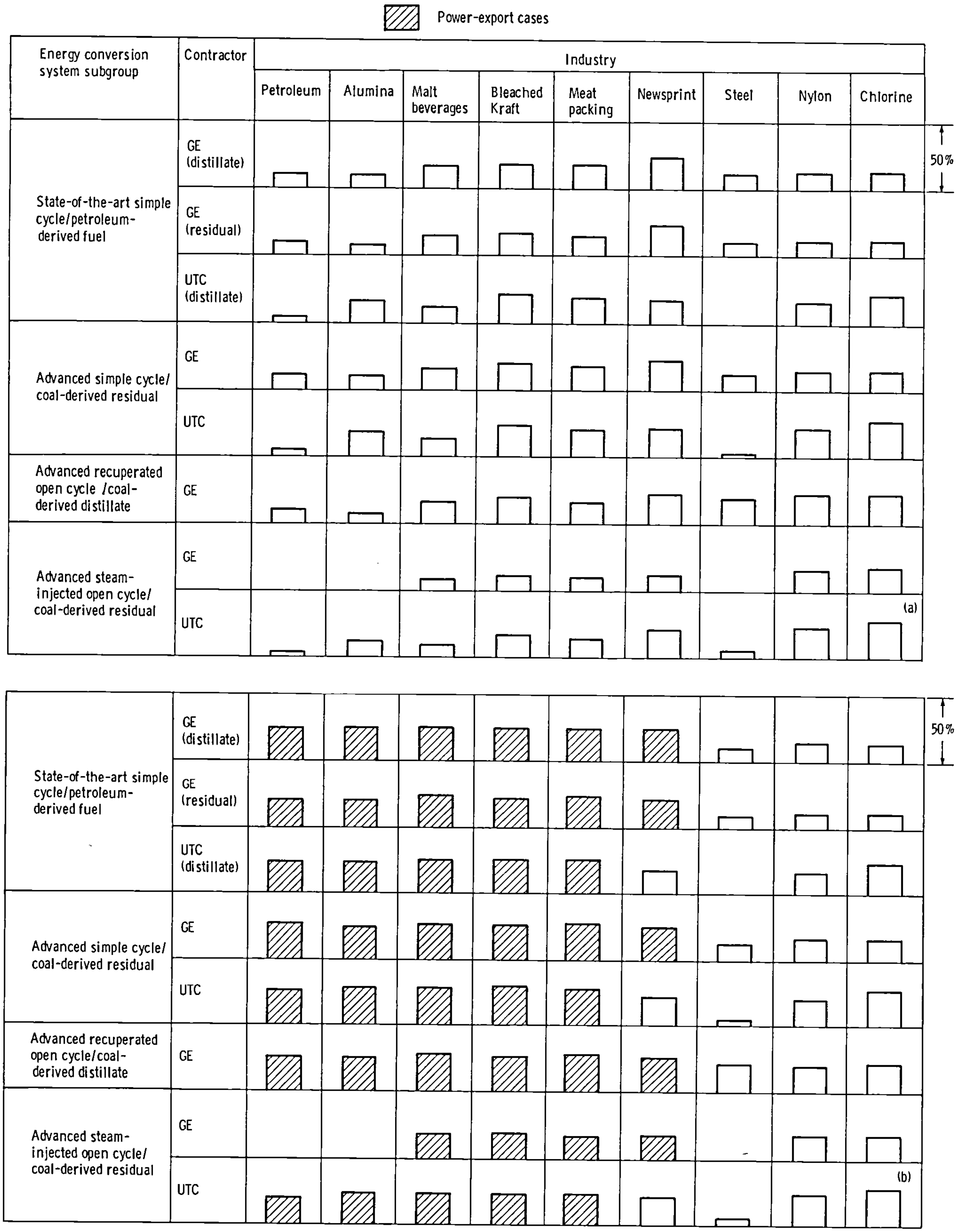
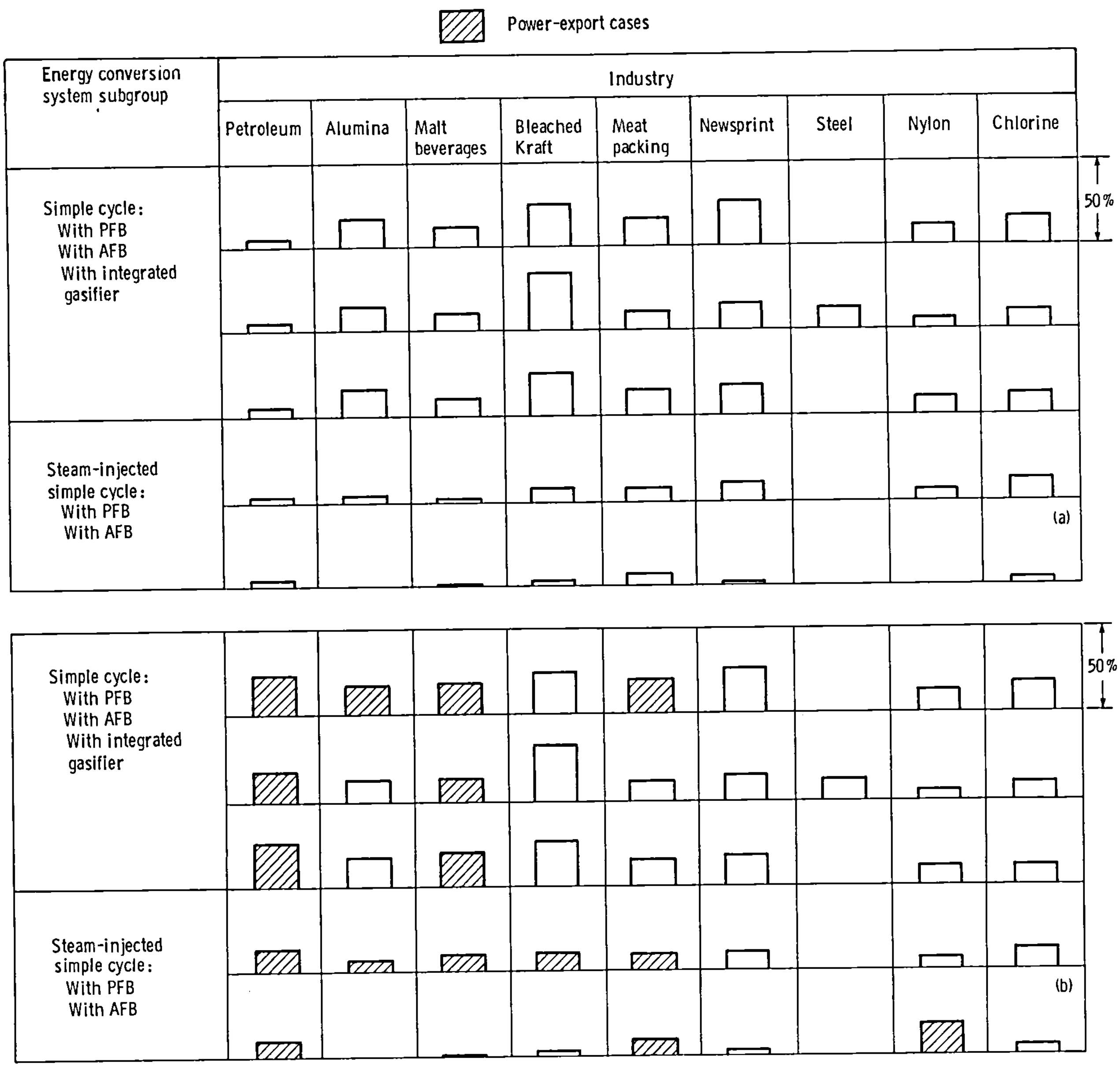


Figure 5.3-11. - Potential fuel energy savings for UTC's coal-fired advanced steam-injected simple-cycle gas turbine systems.



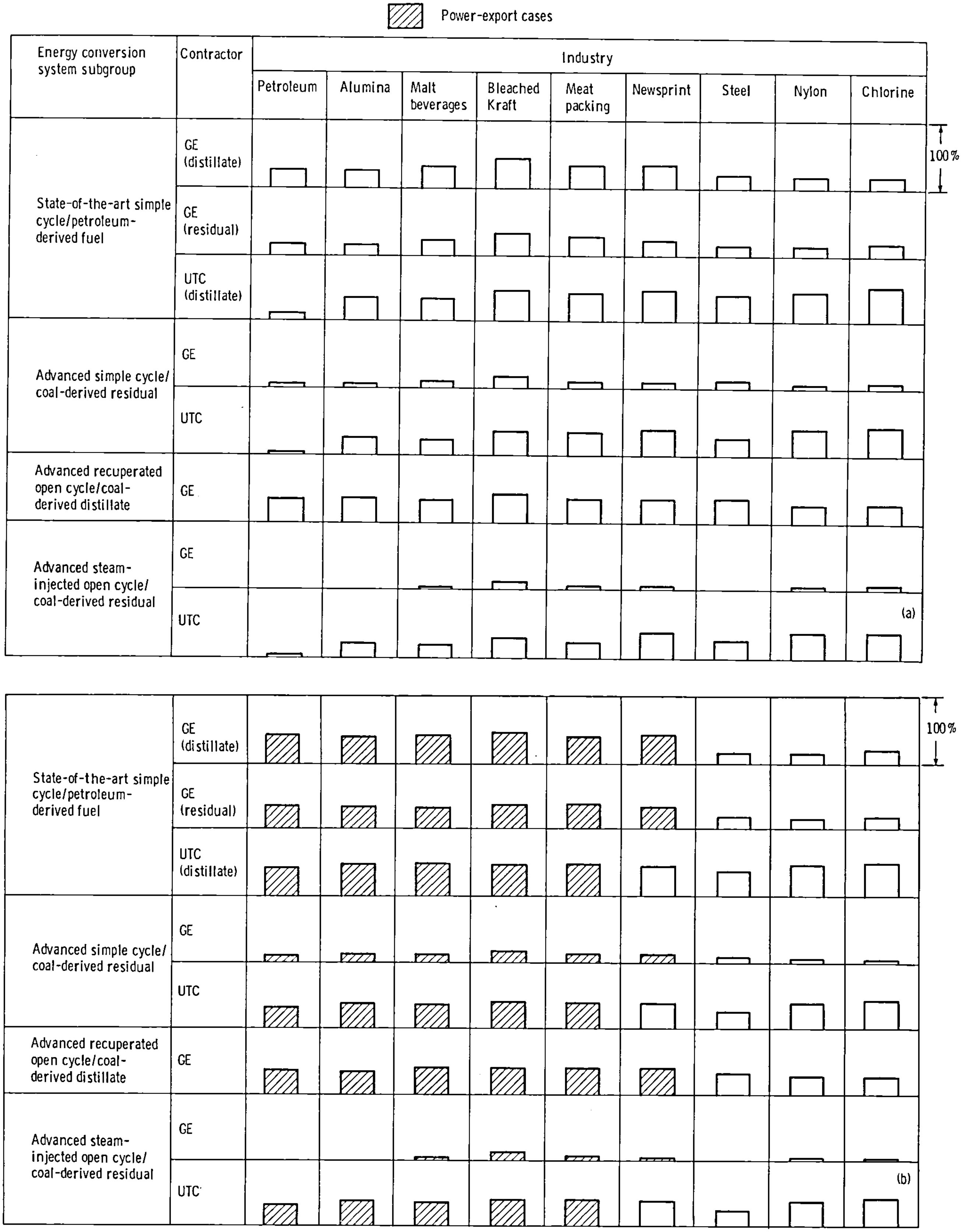
(a) No power export allowed.
(b) Power export allowed.

Figure 5.3-12. - Fuel energy saving ratio for liquid-fueled open-cycle gas turbine systems. (Blanks denote all negative values.)



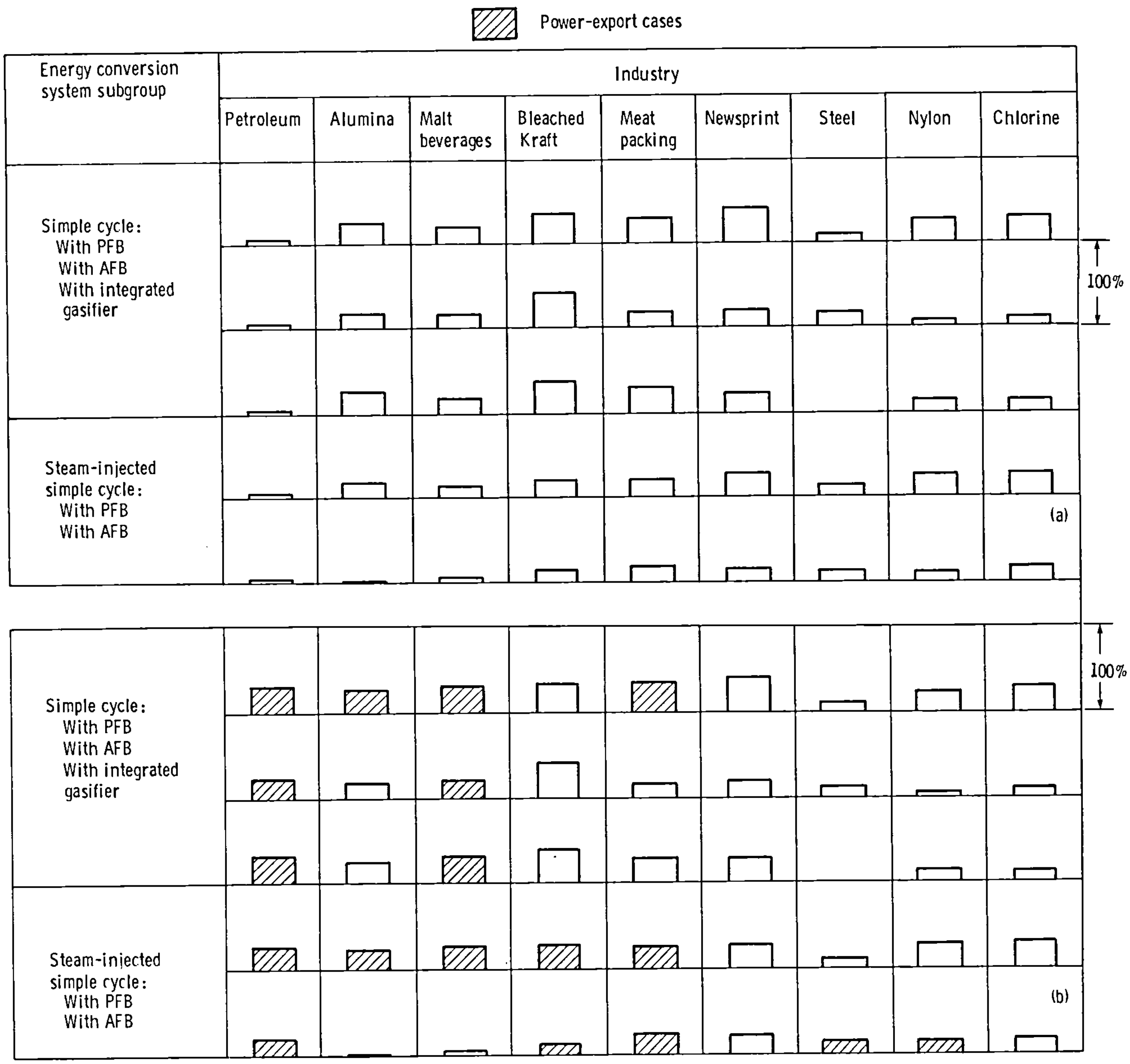
(a) No power export allowed.
(b) Power export allowed.

Figure 5.3-13. - Fuel energy saving ratio for UTC's coal-fired open-cycle gas turbine system. (Blanks denote all negative values.)



(a) No power export allowed.
(b) Power export allowed.

Figure 5.3-14. - Emissions saving ratio for liquid-fueled open-cycle gas turbine systems. (Blanks denote all negative values.)



(a) No power export allowed.
(b) Power export allowed.

Figure 5.3-15. - Emissions saving ratio for coal-fired open-cycle gas turbine systems. (Blanks denote all negative values.)

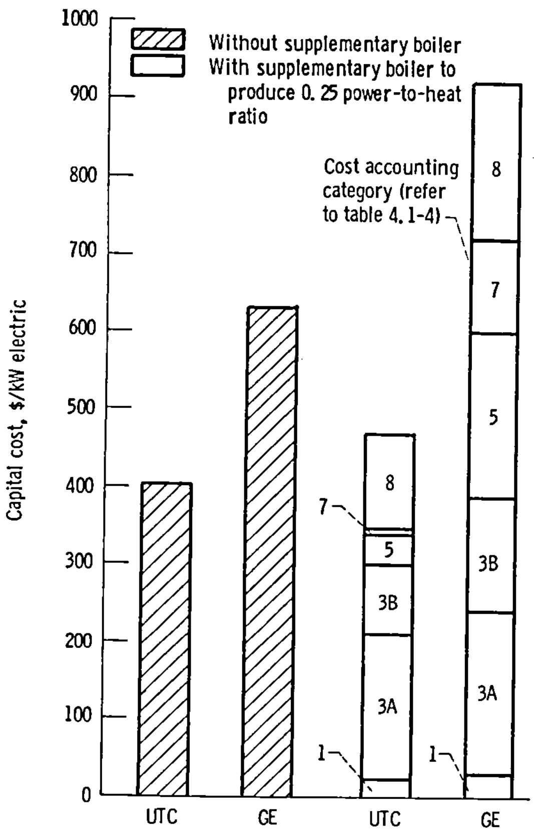
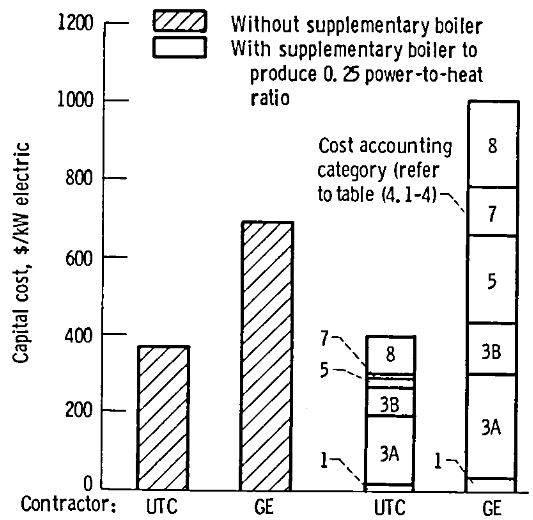


Figure 5.3-16. - Capital costs for state-of-the-art simple-cycle gas turbine distillate systems. Turbine inlet temperature, 2000° F; pressure ratio, 10; electricity generated, 10 MW; process steam temperature, 300° F.



Contractor:	UTC	GE	UTC	GE
Turbine inlet temperature, °F:	2500	2200	2500	2200
Pressure ratio:	18	16	18	16
Supplementary boiler fired?:	Yes	No	Yes	No
ECS power-to-heat ratio:	0.333	0.732	0.333	0.732

Figure 5.3-17. - Capital costs for advanced simple-cycle gas turbine/coal-derived residual systems. Electricity generated, 10 MW; process steam temperature, 300° F.

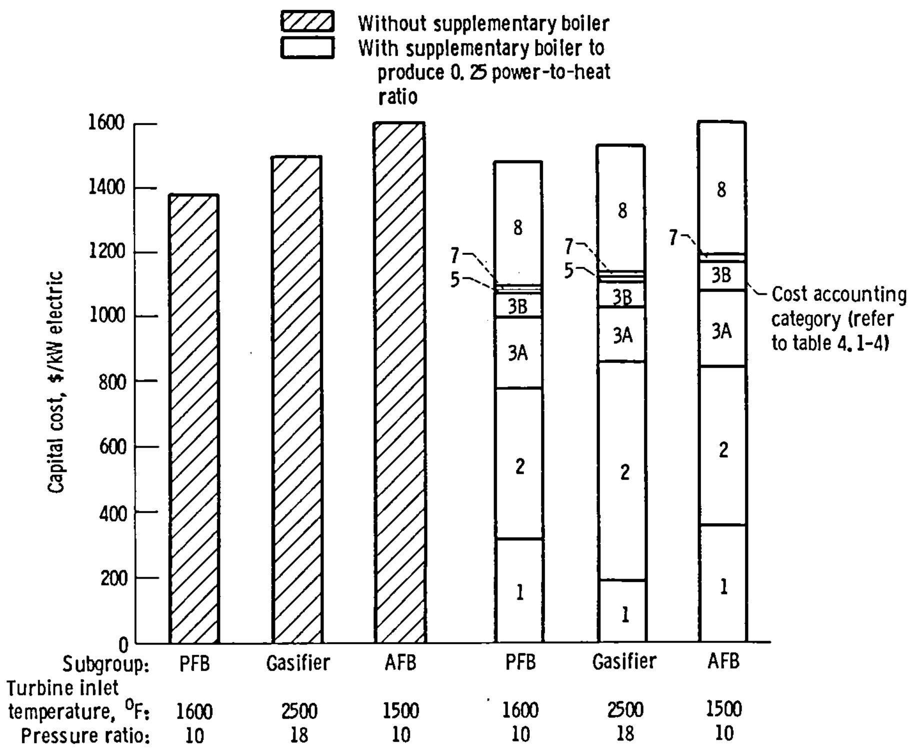


Figure 5.3-18. - Capital costs for UTC's coal-fired advanced simple-cycle gas turbine system. Electricity generated, 10 MW; process steam temperature, 300° F. (AFB systems do not need a supplementary boiler.)

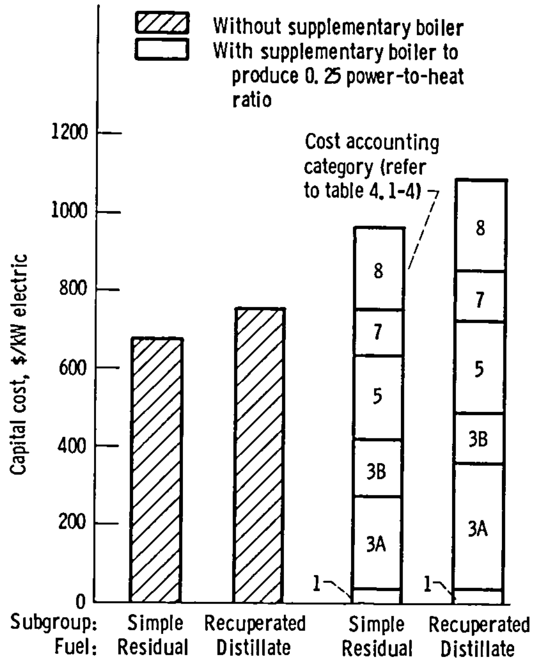


Figure 5.3-19. - Capital costs for GE advanced simple and recuperated open-cycle gas turbine/coal-derived liquid systems. Electricity generated, 10 MW; process steam temperature, 300° F; turbine inlet temperature, 2200° F; pressure ratio, 12; recuperator effectiveness, 0.85.

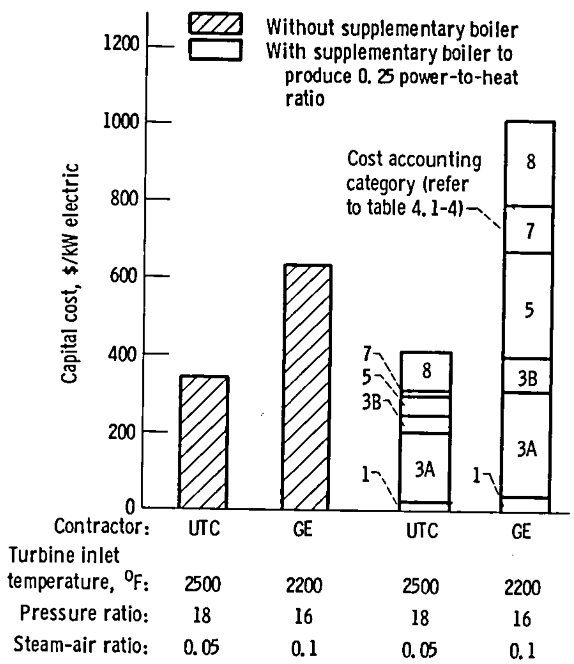


Figure 5.3-20. - Capital costs for advanced steam-injected, simple-cycle gas turbine/coal-derived residual systems. Electricity generated, 10 MW; process steam temperature, 300° F.

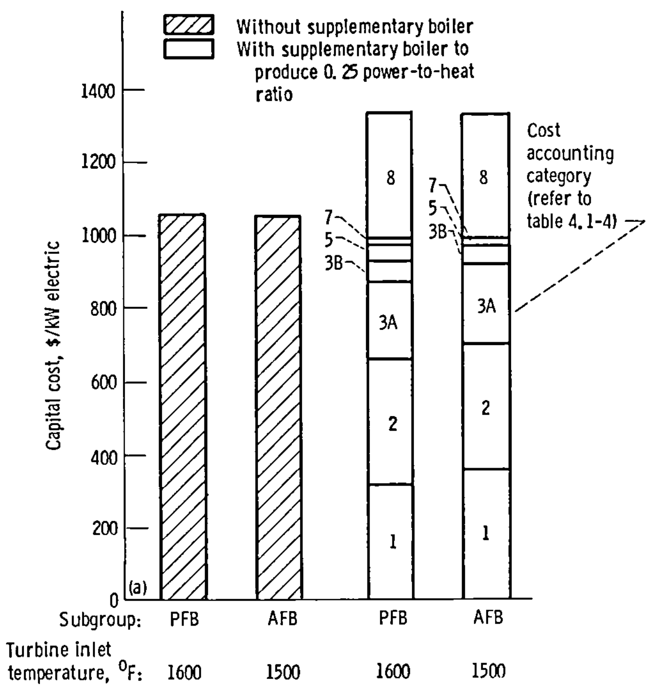
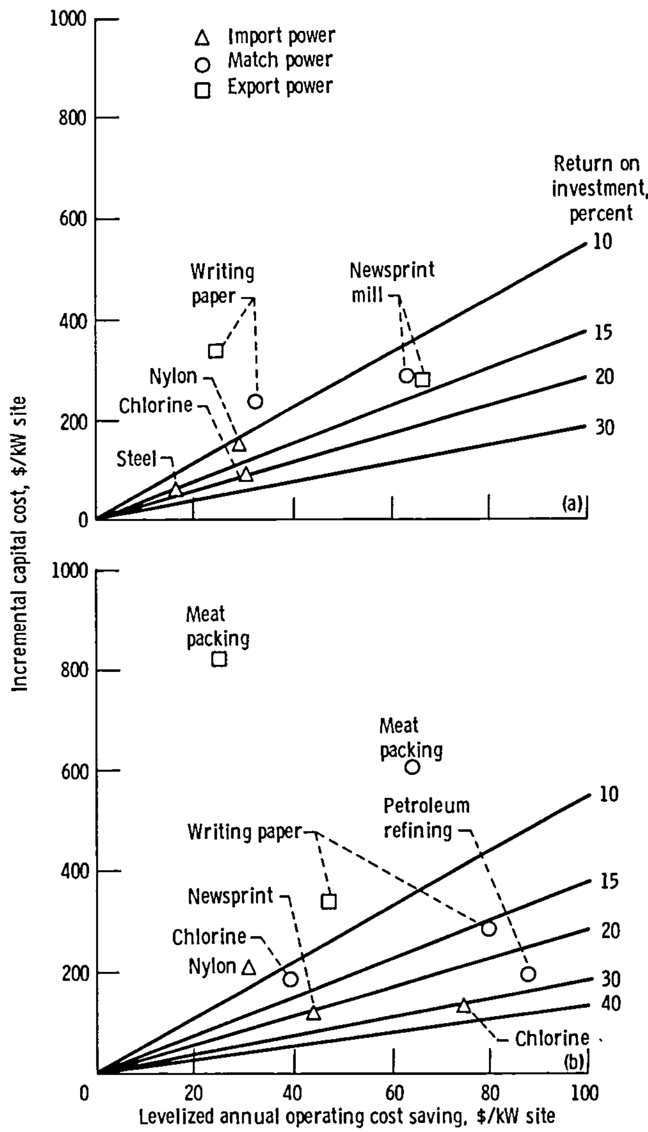


Figure 5.3-21. - Capital costs for UTC's advanced coal-fired steam-injected, simple-cycle gas turbine system. Electricity generated, 10 MW; process steam temperature, 300° F; pressure ratio, 10; steam/air ratio, 0.05.



(a) GE.
(b) UTC.

Figure 5.3-22. - Incremental capital cost as a function of levelized annual operating cost saving for state-of-the-art simple-cycle gas turbine/petroleum distillate systems.

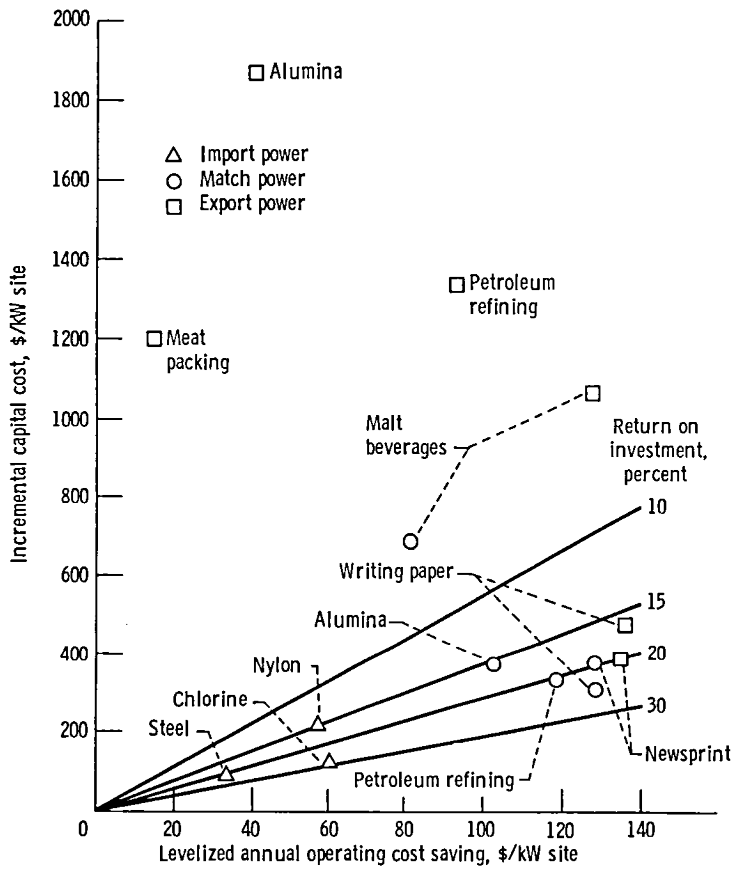
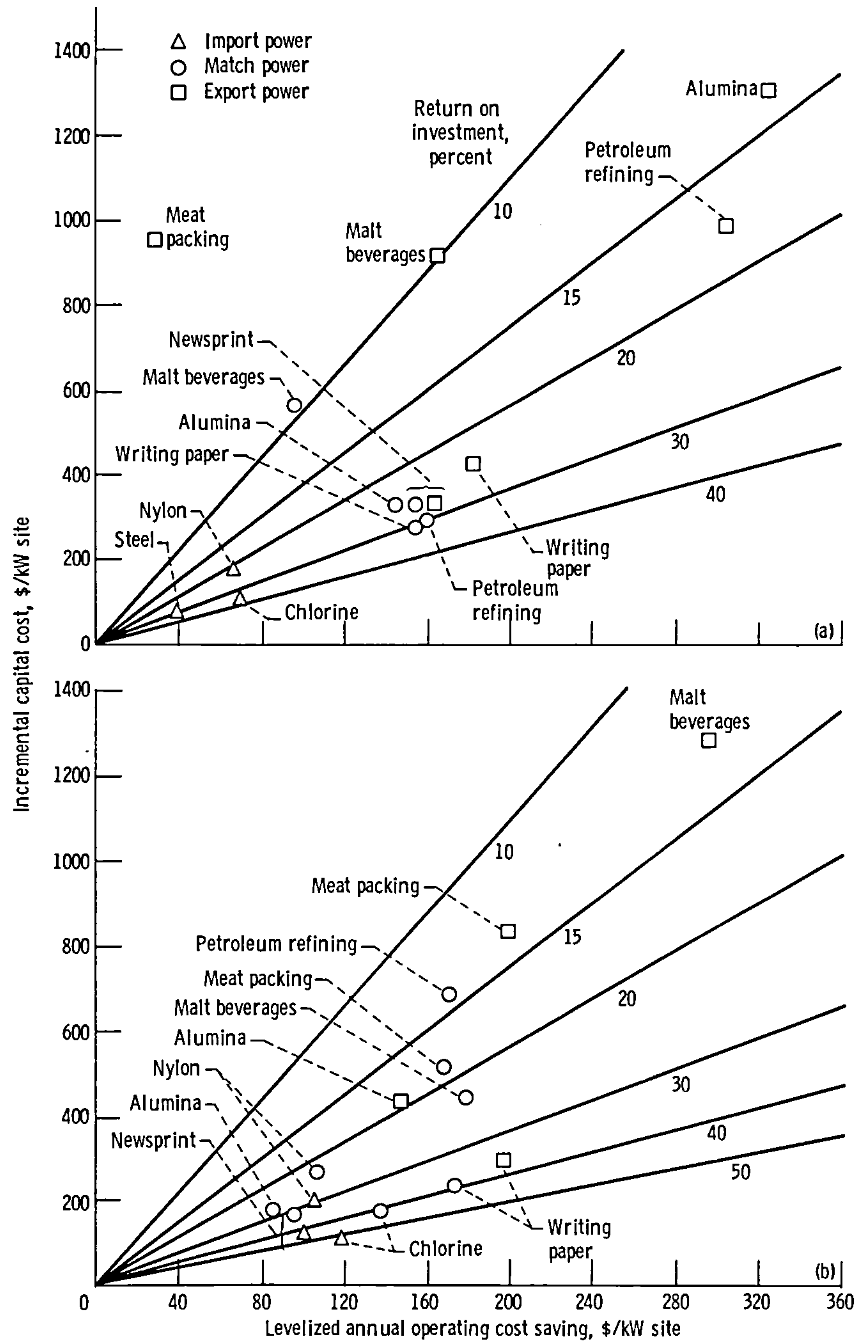


Figure 5.3-23. - Incremental capital cost as a function of levelized annual operating cost savings for GE's state-of-the-art simple-cycle gas turbine/residual system.



(a) GE.
(b) UTC.

Figure 5.3-24. - Incremental capital cost as a function of levelized annual operating cost saving for advanced simple-cycle gas turbine/coal-derived residual systems.

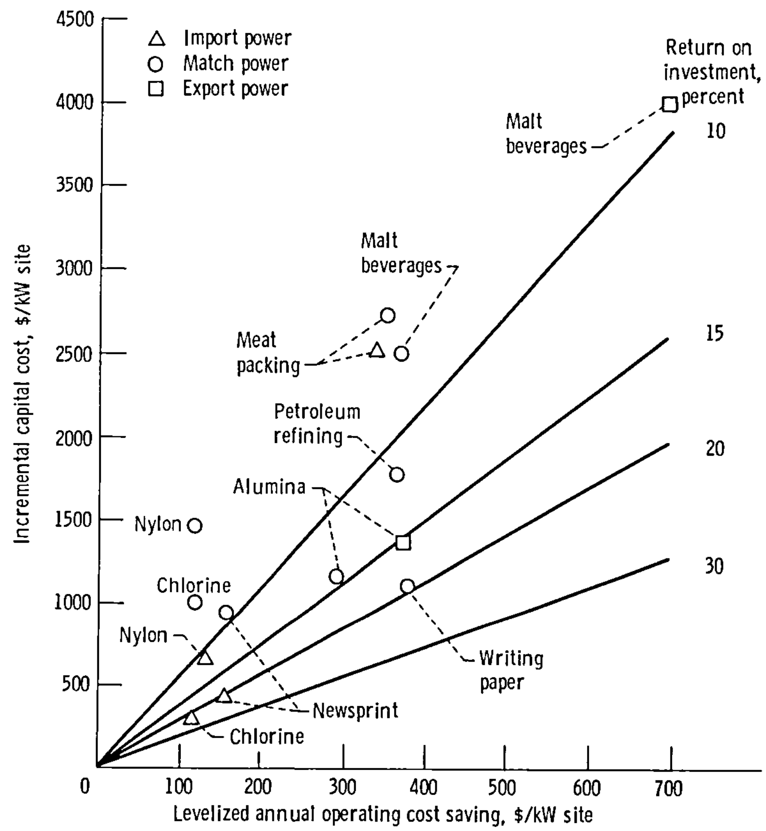


Figure 5.3-25. - Incremental capital cost as a function of levelized annual operating cost saving for UTC's advanced simple-cycle gas turbine/integrated coal gasifier system.

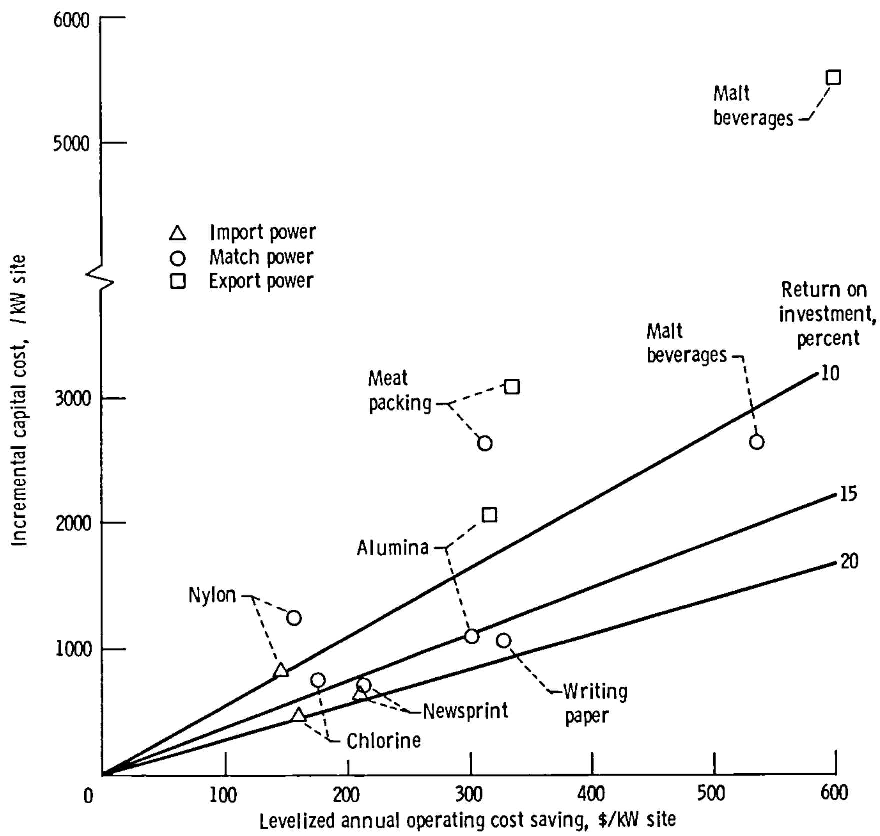


Figure 5.3-26. - Incremental capital cost as a function of levelized annual operating cost saving for UTC's advanced coal-fired simple-cycle gas turbine system.

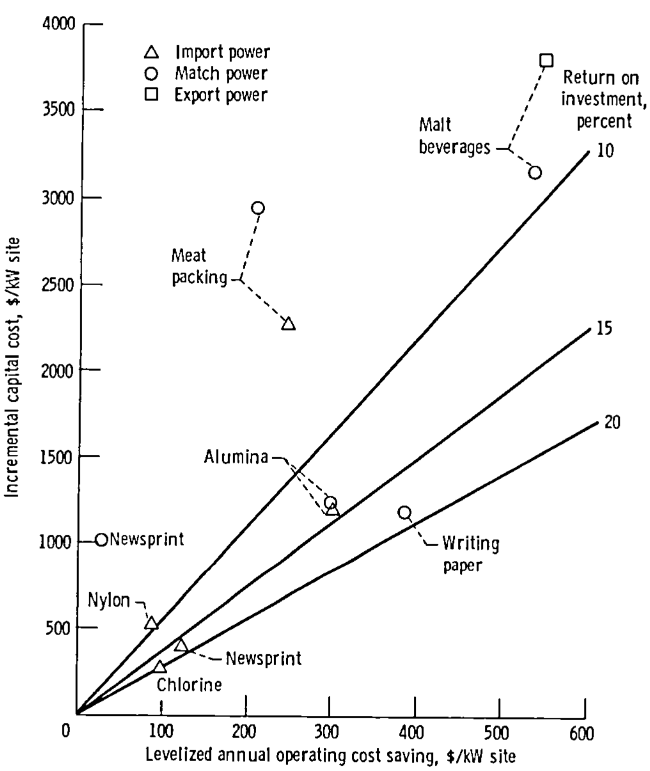


Figure 5.3-27. - Incremental capital cost as a function of levelized annual operating cost saving for UTC's advanced simple-cycle gas turbine/AFB system.

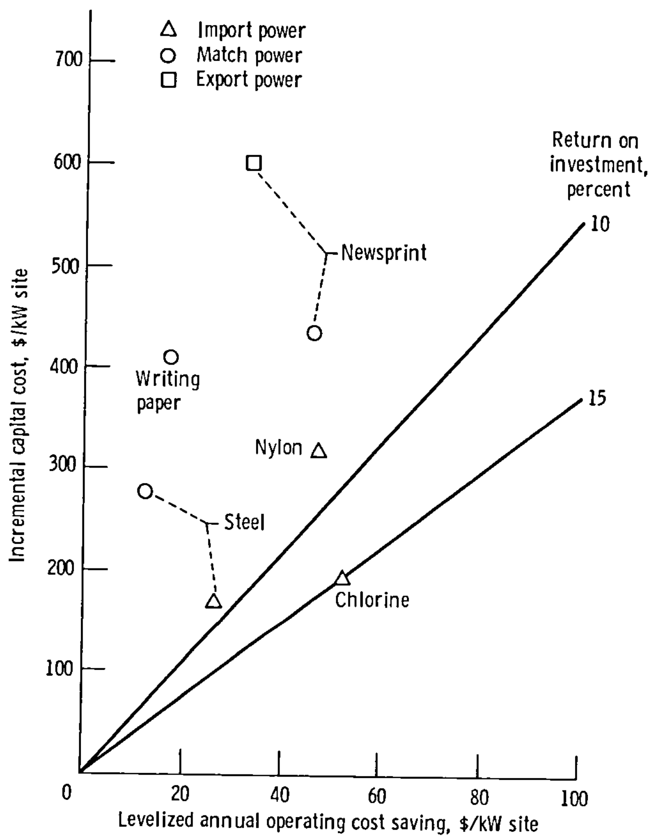
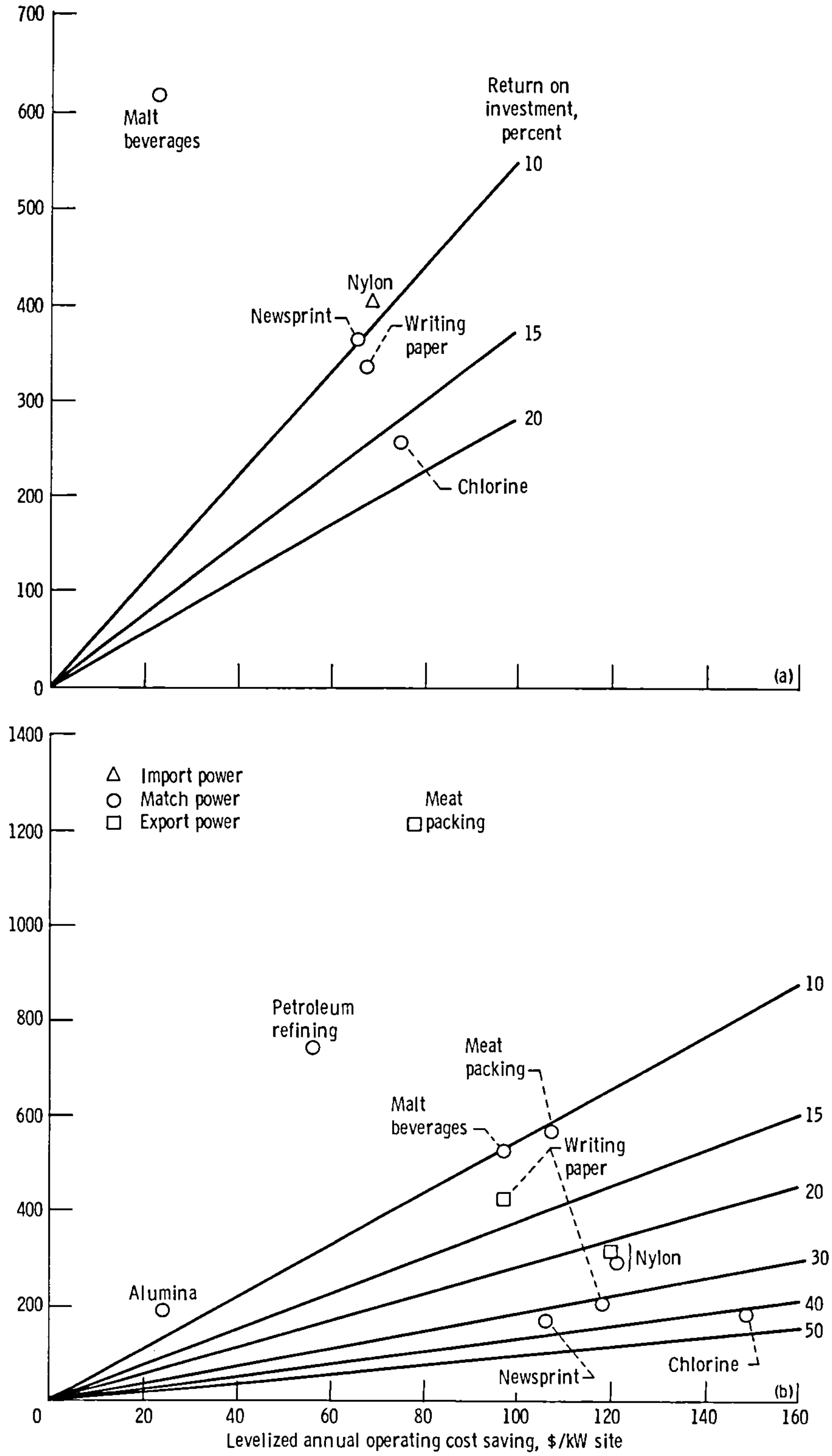


Figure 5.3-28. - Incremental capital cost as a function of levelized annual operating cost saving for GE's advanced recuperated open-cycle gas turbine/coal-derived distillate system.



(a) GE.
(b) UTC.

Figure 5.3-29. - Incremental capital cost as a function of levelized annual operating cost saving for advanced simple-cycle, steam-injected gas turbine/coal-derived residual systems.

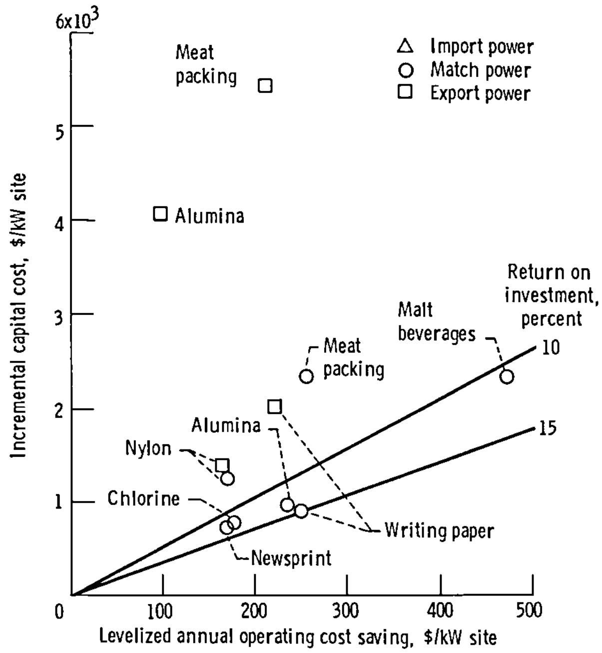


Figure 5.3-30. - Incremental capital costs for UTC's advanced simple-cycle, steam-injected gas turbine/PFB system.

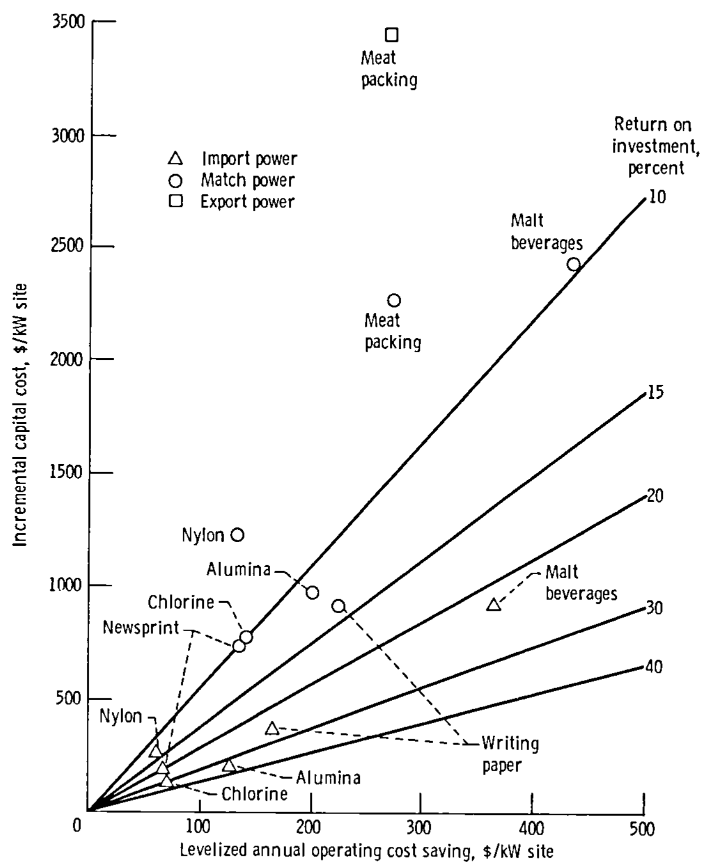
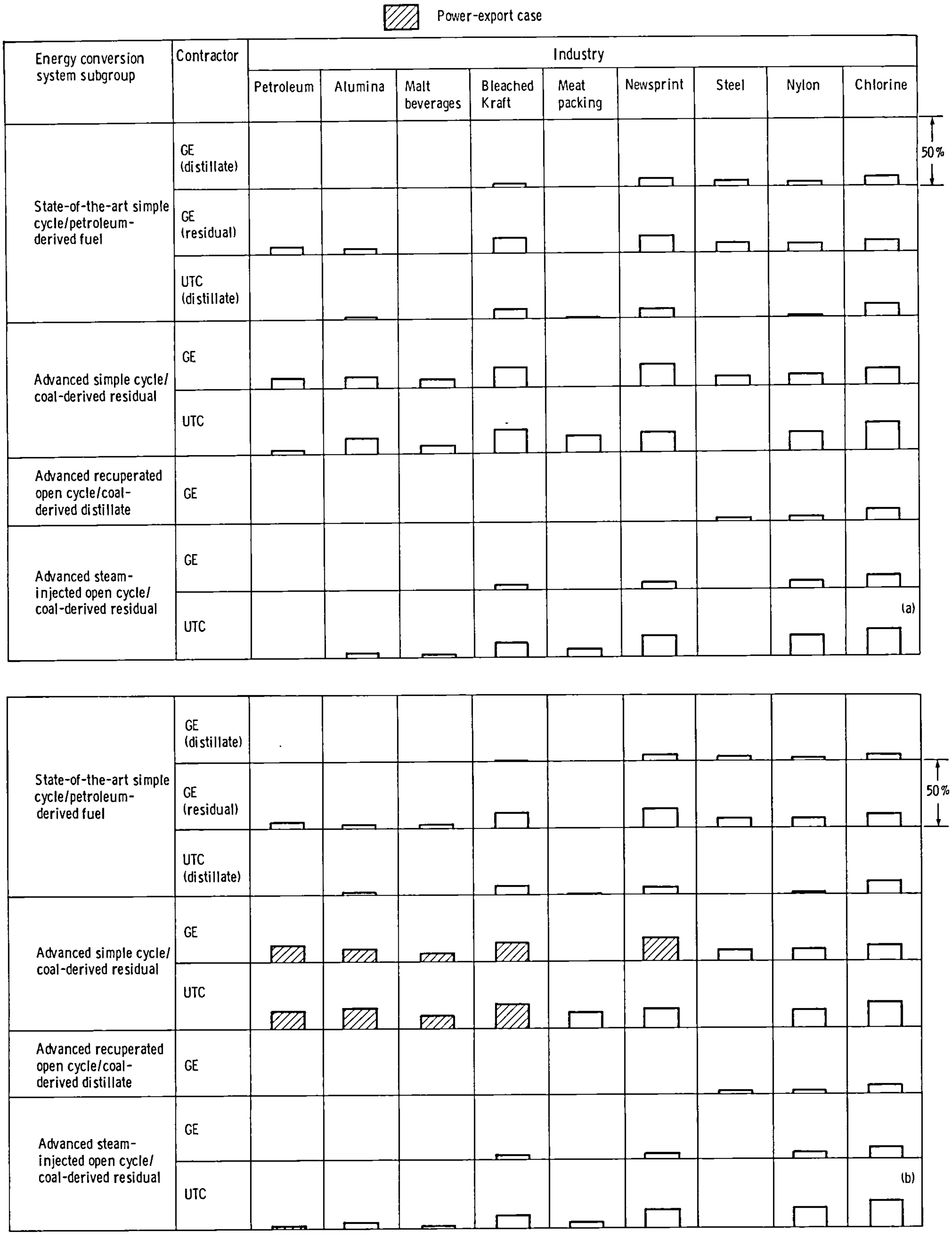
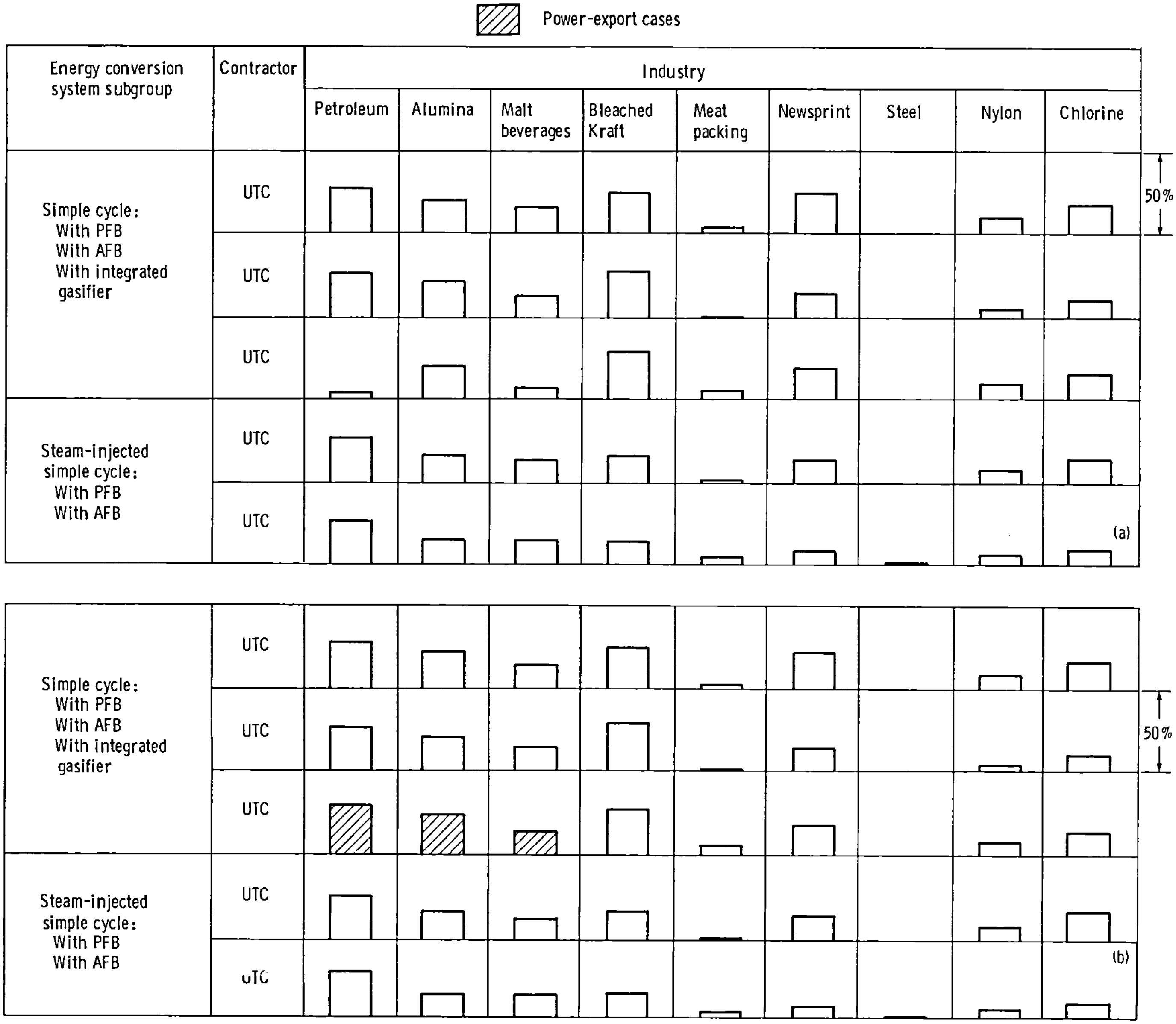


Figure 5.3-31. - Incremental capital cost as a function of levelized annual operating cost saving for UTC's advanced simple-cycle, steam-injected gas turbine/AFB system.



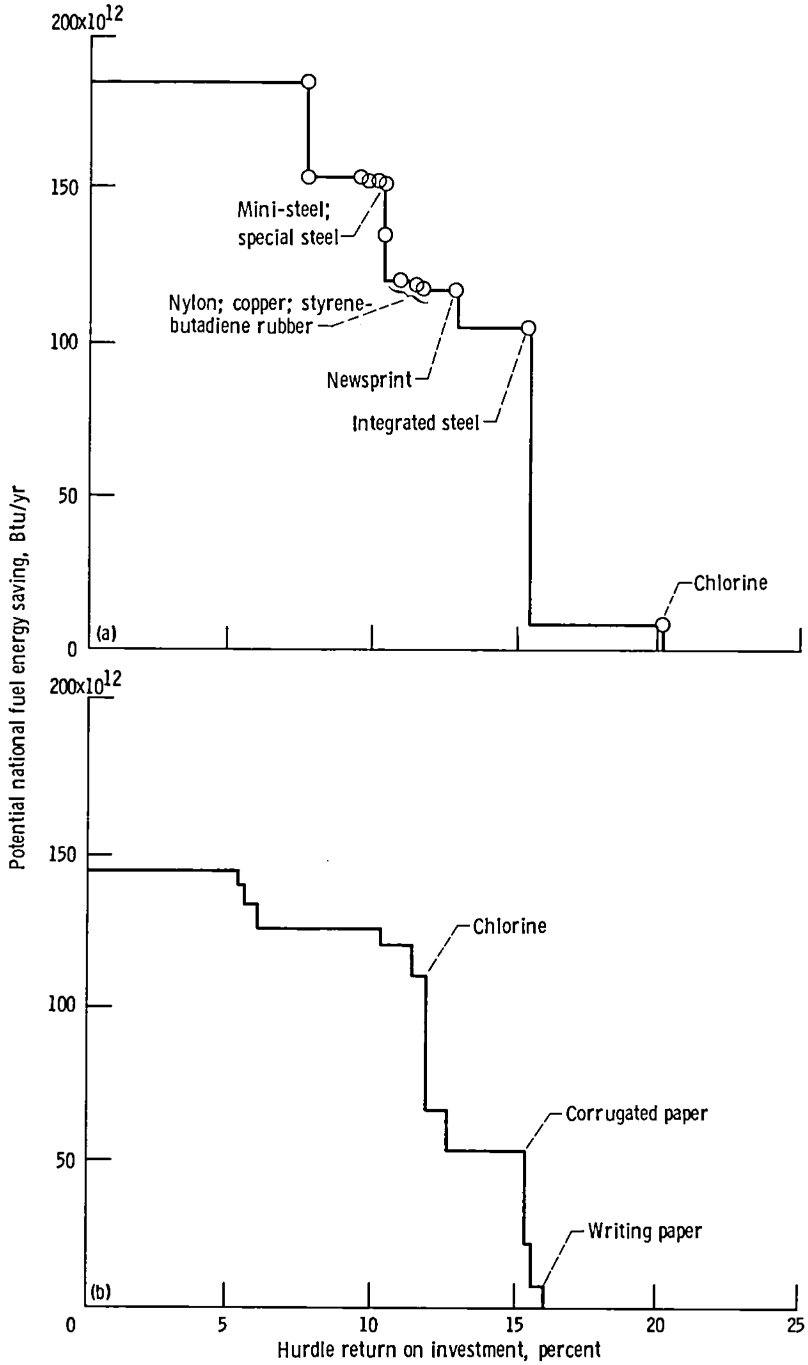
(a) No power export allowed.
(b) Power export allowed.

Figure 5.3-32. - Levelized annual energy cost saving ratios for liquid-fueled open cycle gas turbine systems. (Blanks denote all negative values.)



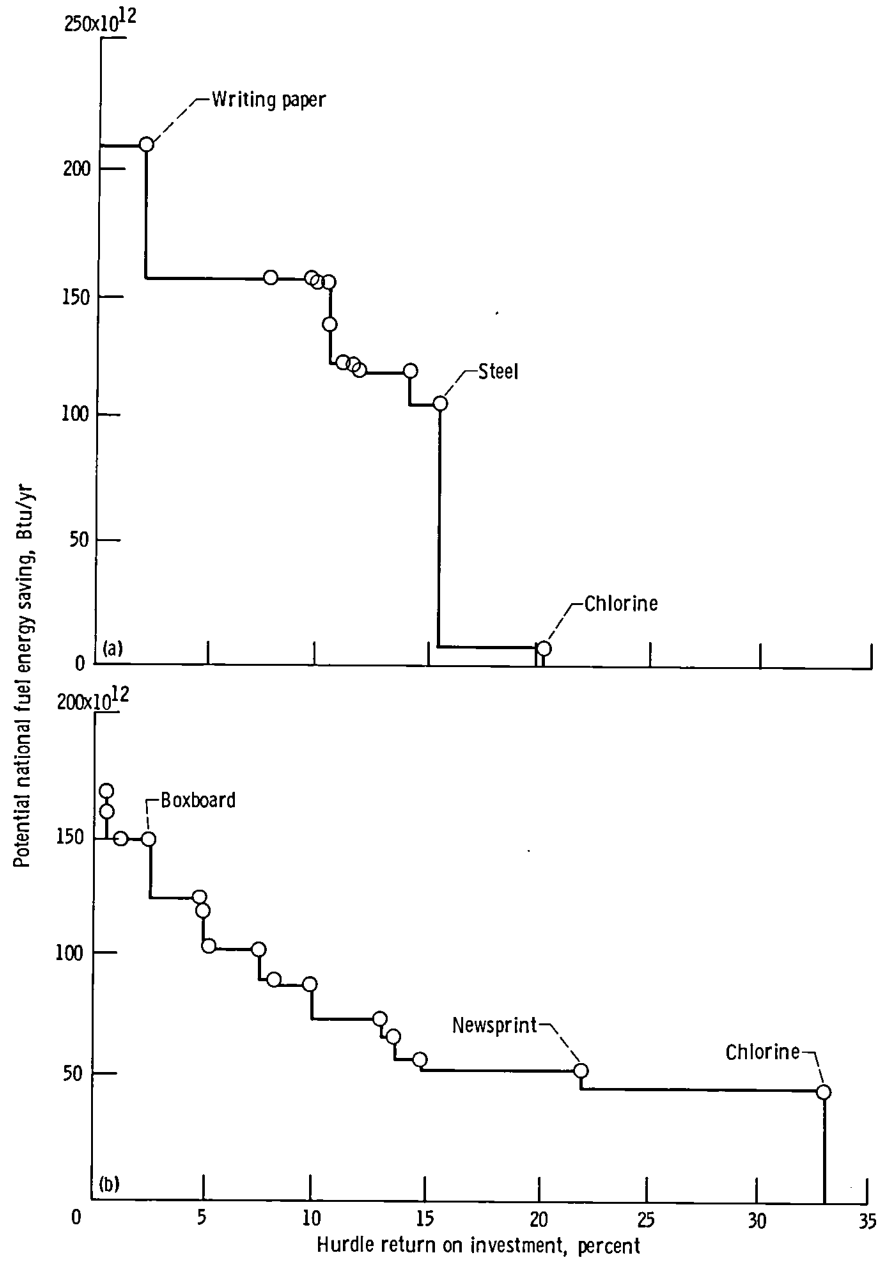
(a) No power export allowed.
(b) Power export allowed.

Figure 5.3-33. - Levelized annual energy cost saving ratios for coal-fired open-cycle gas turbine systems. (Blanks denote all negative values.)



(a) GE.
(b) UTC.

Figure 5.3-34. - Potential national fuel energy saving as a function of hurdle return on investment for state-of-the-art simple-cycle gas turbine/distillate system. (No power export allowed.)



(a) GE.
(b) UTC.

Figure 5.3-35. - Potential national fuel energy saving as a function of hurdle return on investment for state-of-the-art simple-cycle gas turbine/distillate system. (Power export allowed.)

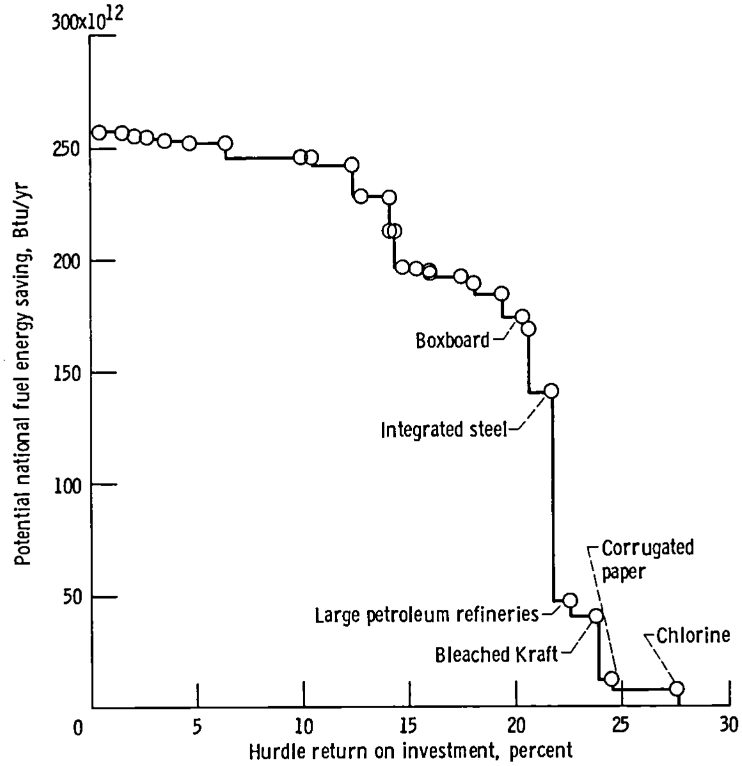
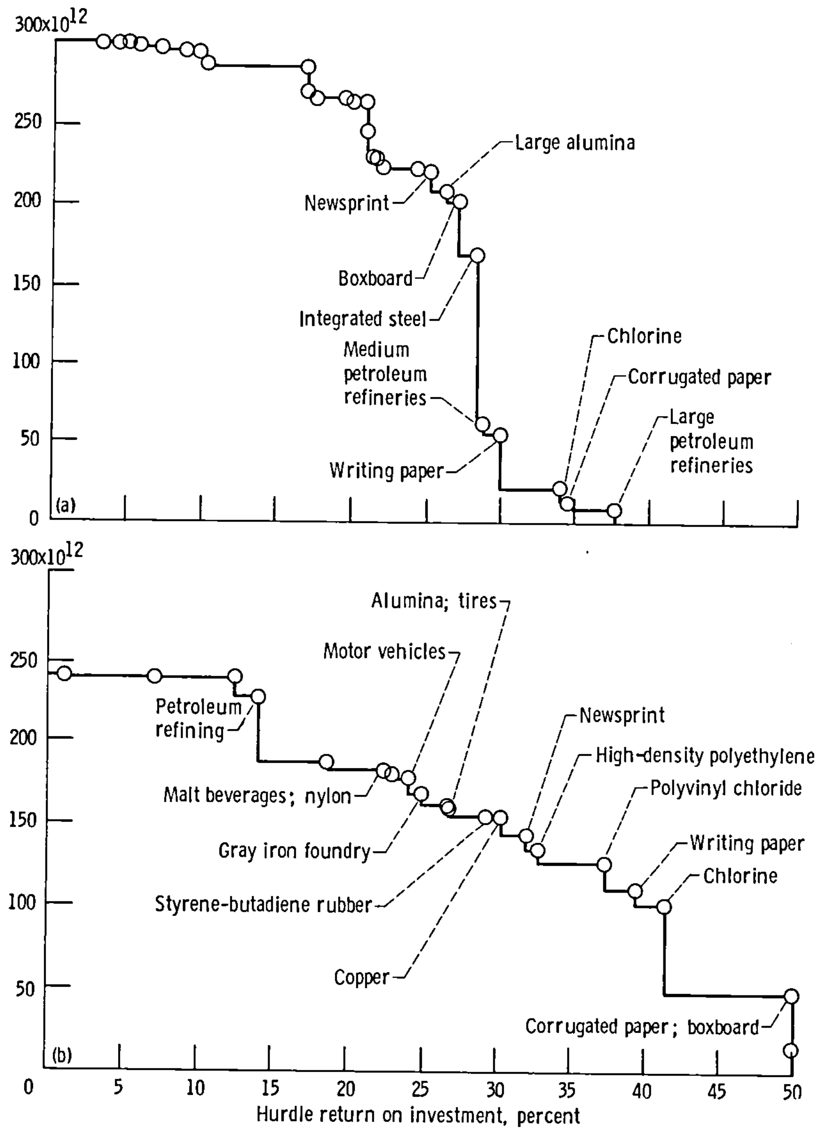


Figure 5.3-36. - Potential national fuel energy saving as a function of hurdle return on investment for GE's state-of-the-art simple-cycle gas turbine/ residual system. (No power export allowed.)



(a) GE.
(b) UTC.

Figure 5.3-37. - Potential national fuel energy saving as a function of hurdle return on investment for advanced simple-cycle gas turbine/coal-derived residual systems. (No power export allowed.)

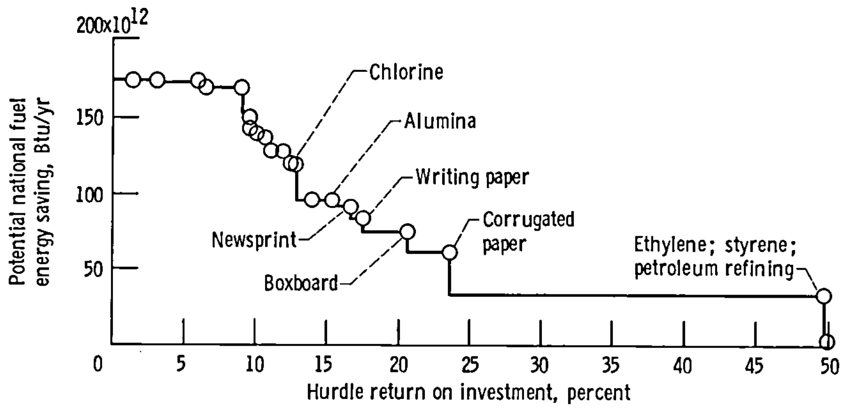


Figure 5.3-38. - Potential national fuel energy saving as a function of hurdle return on investment for UTC's advanced simple-cycle gas turbine/PFB system. (No power export allowed.)

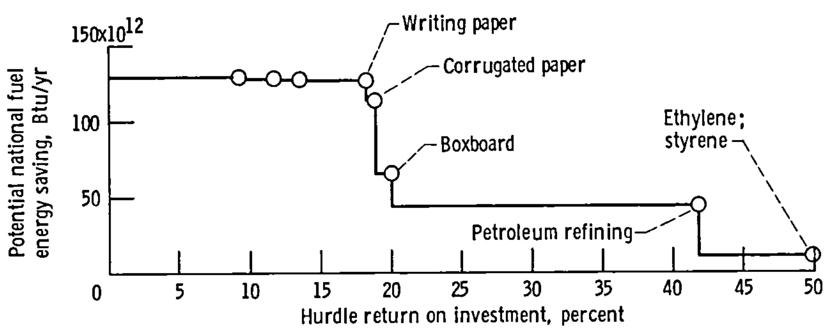


Figure 5.3-39. - Potential national fuel energy saving as a function of hurdle return on investment for UTC's advanced simple-cycle gas turbine/AFB system. (No power export allowed.)

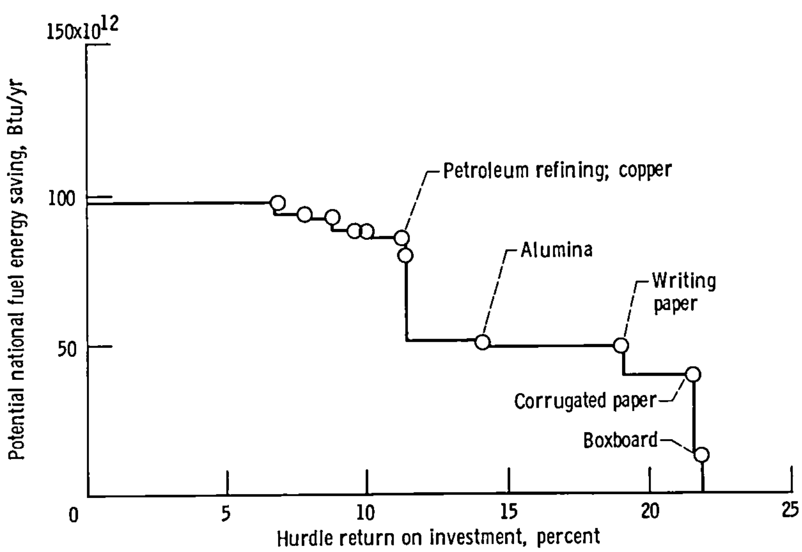
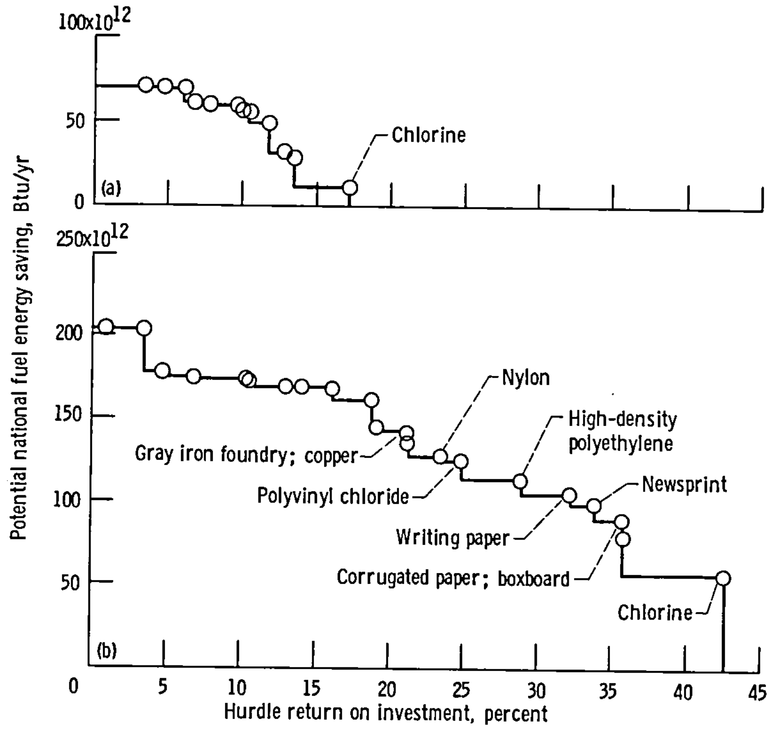


Figure 5.3-40. - Potential national fuel energy saving as a function of hurdle return on investment for UTC's advanced simple-cycle gas turbine/integrated gasifier system. (No power export allowed.)



(a) GE.
(b) UTC.

Figure 5.3-41. - Potential national fuel energy saving as a function of hurdle return on investment for advanced steam-injected, simple-cycle gas turbine/ coal-derived residual systems. (No power export allowed.)

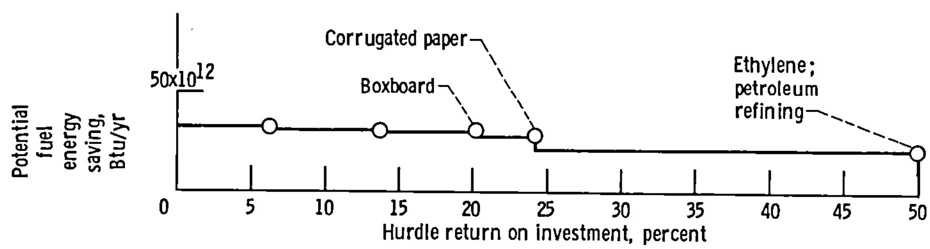


Figure 5.3-42. - Potential national fuel energy saving as a function of hurdle return on investment for UTC's advanced steam-injected, simple-cycle gas turbine/AFB system. (No power export allowed.)

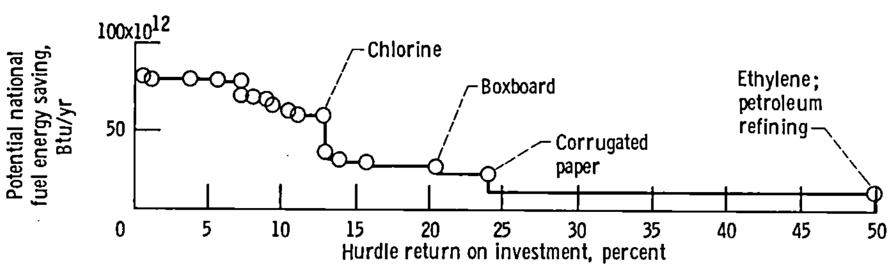


Figure 5.3-43. - Potential national fuel energy saving as a function of hurdle return on investment for UTC's advanced steam-injected, simple-cycle gas turbine/PFB system. (No power export allowed.)

5.4 GAS TURBINE/STEAM TURBINE COMBINED-CYCLE SYSTEMS

Yung K. Choo

5.4.1 Configurations and Parameters

The major parameters and configurations of gas turbine/steam turbine combined-cycle systems studied by each contractor are summarized in table 5.4-1. Both contractors considered systems using residual fuel and systems using coal. For coal-fired systems GE considered a combined cycle with an integrated gasifier and UTC considered combined cycles with AFB and PFB furnaces. (A gas turbine system with a coal-fired integrated gasifer examined by UTC is discussed in the previous section.) UTC considered a state-of-the-art combined cycle using distillate-grade fuel. GE used a noncondensing back-pressure steam turbine that exhausts steam at a pressure desired by a process. UTC used a straight condensing steam turbine for each combined cycle studied.

The configurations of the advanced combined cycles using residual fuel that were studied by the two contractors are shown in figure 5.4-1. Advancement is in the higher gas turbine inlet temperature and the use of residual fuel. The GE system (fig. 5.4-1(a)) uses a noncondensing back-pressure steam turbine. The exhaust pressure is varied to meet the process steam pressure. Effects of the exhaust steam pressure and other parameters such as pressure ratio are discussed in the next section. In the GE design all steam generated in the heat-recovery steam generator (HRSG) is expanded through the steam turbine except a small fraction for the deaerator. The UTC system (fig. 5.4-1(b)) used a straight condensing steam turbine. The HRSG steam flow is divided in two for the steam turbine and industrial process. Process steam is taken directly from the HRSG instead of being extracted from the turbine. The ratio of the two steam flows, which was selected as a design parameter, affects the system power-to-heat ratio.

Figure 5.4-2 shows the configurations of the combined cycles using coal that were studied by the contractors. Figure 5.4-2(a) shows the configuration of the GE combined cycle with an integrated gasifier. Advancement is in the use of a medium-Btu gasifier and its integration to the combined cycle. The gasifier used is an oxygen-blown, entrained-bed gasifier. Figure 5.4-2(b) shows the UTC coal-fired systems that have advanced furnace systems - AFB and PFB. Both systems shown have air tubes in the bed, and therefore the gas turbine inlet temperatures are limited by the fluidized-bed temperatures. The gas turbine inlet temperatures are 50 deg F lower than the AFB and PFB temperatures. The bottoming cycle uses a straight condensing turbine, and process steam is taken directly from the HRSG instead of being extracted from the turbine, just as in the residual-fueled system. An alternative configuration with the AFB furnace is shown in figure 5.4-2(c). In this configuration, gas turbine exhaust air is used for the combustion of coal in the AFB furnace. Process steam and steam for the turbine are generated in the steam tubes in the AFB furnace.

NASA, in an effort to understand general cogeneration performance characteristics of combined-cycle systems and the contractors' results, considered three combined-cycle cases (fig. 5.4-3). The open-cycle gas turbine considered by NASA has the following parameters:

Pressure ratio	12
Inlet temperature, °F	2200
Exhaust temperature, °F	1041
Power efficiency	0.314

The first case (fig. 5.4-3(a)) examines the back-pressure effect on system performance. The second case (fig. 5.4-3(b)) has the same configuration as the first-case configuration, but it has a reduced throttle condition so that its effect on the system performance can be examined by comparing it with the case 1 result. The first two cases have the following additional parameters:

Case 1:

Heat-recovery steam generator	Single pressure
Throttle steam condition, psig/°F	1200/950
Steam turbine back pressure, psig	15-300

Case 2:

Heat-recovery steam generator	Single pressure
Throttle steam condition, psig/°F	450/656
Steam turbine back pressure, psig	50

The third case considers a dual-pressure HRSG (fig. 5.4-3 (c)). In this case, process steam is obtained from the HRSG as well as from the steam turbine exhaust:

Case 3:

Heat-recovery steam generator	Dual pressure
Throttle steam condition, psig/°F	1200/950
Low-pressure steam to process, psig	15-20
Steam turbine back pressure, psig	15,50

5.4.2 Cogeneration System Performance

5.4.2.1 Fuel Energy Saving Ratio

For the gas turbine/steam turbine combined-cycle systems discussed in the previous section, figures 5.4-4 to 5.4-6 show the power-to-heat ratios produced by the systems for a range of process steam conditions versus the potential fuel energy savings that could be achieved if the system power-to-heat ratio matched the process needs. As discussed in appendix D, if the site-required power-to-heat ratio differs from the value provided by the system, as shown in the figures, the fuel savings in most cases would be lower than indicated here.

Before discussing the contractors' results, performance of the NASA cases (fig. 5.4-4) is briefly discussed because they explain the general cogeneration performance characteristics of the combined-cycle systems. In case 1 the potential fuel energy saving decreases with increasing back pressure as in the back-pressure steam turbine system (section 5.1). The energy saving versus power-to-heat ratio curve is relatively flat because in the combined cycle the change in back pressure does not have any effect on the topping cycle and hence

both power system efficiency and the amount of heat recovery as indicated by the heat recovery factor are less sensitive to back-pressure changes than is the steam cycle alone. The relatively low heat recovery values are due to a high stack temperature (about 440° F) caused by the pinch-point limit and relatively high throttle steam conditions for the 1041° F gas turbine exhaust.

In case 2 the amount of heat recovery improves as the throttle steam conditions are reduced. The reason is that more heat can be recovered from the 1041° F gas turbine exhaust with lower throttle steam conditions for the same pinch-point temperature difference. The stack temperature is 358° F in this case. In the extreme, when steam is generated at a pressure required by a process, no power can be generated by the steam turbine. This case is then identical to an open-cycle gas turbine HRSG without a steam turbine. Performance of this case is also shown in figure 5.4-4.

In case 3 the heat recovery factor is improved substantially because heat is recovered in the low-pressure section of the HRSG as well as in the high-pressure section. Even though the same amount of high-pressure steam is produced as in case 1, the production of additional low-pressure steam reduces the exhaust stack temperature to 275° F from the 430° F in case 1.

Figure 5.4-5 shows the power-to-heat ratios and potential fuel energy savings that could be achieved when the residual-fueled combined-cycle systems exactly meet the needs of the site power-to-heat ratio. For the same reason explained in connection with the NASA case 1, each GE system with a selected gas turbine topping cycle and a fixed throttle steam condition has decreasing potential fuel energy saving with increasing back pressure of the steam turbine. The temperatures on the GE curves indicate saturation steam temperatures corresponding to the turbine exhaust pressures. The difference between the two GE air-cooled systems is due to the different amount of waste heat recovery for the two different pressure ratios for the same gas turbine inlet temperature of 2200° F and throttle steam condition of 1465 psia/1000° F. The system with a pressure ratio of 8 recovers more waste heat than the system with a pressure ratio of 12. This is because the reduction in the pressure ratio causes an increase in the gas turbine exhaust temperature and that permits more heat recovery in the HRSG for the same pinch-point temperature difference and throttle steam condition. Changing the pressure ratio of the air-cooled system from 16 to 12, however, affects the performance a negligible amount because of the small change in gas turbine performance. Performance of the UTC combined cycle using residual fuel is shown by a solid circle in the figure. The system power-to-heat ratio is an independently selected parameter in the UTC design. As pointed out in the previous section and in figure 5.4-1(b), it was selected by choosing the fraction of total HRSG steam to be taken for process steam. Among the three UTC design options indicated in table 5.4-1 for three steam extraction rates for process, the case with the lowest power-to-heat ratio of 1.3 (designated as design option 3 by UTC) is shown in figure 5.4-5 because this case showed the best cogeneration results in the representative subset of nine industries.

The performance potential of coal-fired, gas turbine/steam turbine combined-cycle systems is shown in figure 5.4-6. The GE combined cycle with an integrated gasifier has a relatively high waste heat recovery as compared with the UTC coal-fired systems and the residual-fueled systems. But its electrical efficiency is substantially lower than that of the residual-fueled systems, mainly because of the additional power required by the oxygen separa-

tion plant and the gasifier compressor. UTC's two coal-fired systems operate at lower gas turbine inlet temperatures because of the operating temperature limit of the AFB and PFB for optimum sulfur removal. According to figure D-1 of appendix D those systems with lower gas turbine inlet temperatures have lower electrical efficiency than the residual-fueled system, which operates at a higher temperature. The UTC AFB system has lower electrical efficiency than the PFB system, which generates power in both the gas and steam turbines.

Fuel energy saving ratio (FESR) results of the gas turbine/steam turbine combined-cycle systems matched to the nine representative industries are shown in figure 5.4-7. The processes are listed in the ascending order of power-to-heat ratio from left to right. The characteristics of these processes are listed in section 3.2. UTC results for alumina and integrated steel were modified by NASA to exclude the direct-heat requirements. The direct heat specified by UTC for the integrated-steel case is the heat that could be provided by the coking coal. The UTC alumina case requires burning a specified clean fuel for the direct heat to calcine the alumina. The UTC petroleum case also requires a substantial amount of direct heat, but results were not modified by NASA because modification involves changes in the energy converison system, which supplies hot gas for a part of the direct-heat requirement rather than process steam. It should be noted that the direct heat for the UTC petroleum case does not require any specified fuel. UTC, therefore, switches fuel from residual fuel in the noncogeneration case to coal in the cogeneration cases for direct heat when using the coal-fired combined cycles with AFB and PFB. This fuel switching results in an exaggerated operating cost saving by the coal-fired systems for the UTC petroleum case as in shown later. In its modification NASA used the byproduct fuel (coke-oven gas and black furnace gas available for process) from the UTC integrated-steel case in boilers and the AFB furnace. But the byproduct fuel was not used in the PFB and the residual oil combustor, which operate at high pressures.

Figure 5.4-7(a) shows the FESR results when no power export is allowed. Both contractors' results indicate that the residual-fueled systems achieve higher FESR values than the coal-fired systems. This is due to the higher potential fuel energy savings that can be achieved by the residual-fueled systems, as shown in figure 5.4-5. The residual-fueled systems achieve higher FESR's as the industry power-to-heat ratio increases because of their better match with these industries. The exception is the integrated-steel case, which requires steam at a relatively high temperature, at which the GE system has somewhat low potential FESR according to figure 5.4-5. The UTC integrated-steel, noncogeneration case used more free byproduct fuel than the cogeneration case because the latter combustor is not allowed to use the byproduct fuel.

The UTC combined cycle with an AFB furnace and the GE combined cycle with an integrated gasifier show high FESR results in the newsprint mills, because they have well-matching power-to-heat ratios. The UTC system with AFB shows relatively low FESR results in the alumina and chlorine processes because these processes require steam at relatively high temperatures, at which the system FESR potential is low. The UTC system with the AFB shows a high FESR in the integrated-steel case because it burns the free byproduct fuel in the AFB as well as in the supplementary boiler. In the integrated steel case byproduct fuel is not allowed to burn in the GE gasifier and the UTC PFB, which operate at high pressures. The UTC combined cycle with the PFB shows high FESR values in the newsprint, nylon, and chlorine industries because of the relatively

closer power-to-heat ratio match. But it shows no fuel energy saving in the integrated-steel case because byproduct fuel is used in the noncogeneration on-site boiler and not in the PFB.

The FESR results when power export is allowed are shown in figure 5.4-7(b). Power-export cases are denoted by cross-hatched bars. The FESR values are improved in many cases where a larger power system is used and making excess power results in a greater amount of heat recovery for process use. The excess power exported is accounted for in the FESR calculation. Comparison of figures 5.4-7(a) and (b) shows that the improvement is greater for the processes with the lower power-to-heat ratios. The lower the site-required power-to-heat ratio as compared with that produced by the system, the greater the amount of excess power produced in the match-heat strategy. This will affect the economic results as illustrated in later figures and parametrically in appendix D.

5.4.2.2 Emission Saving Ratio

The emissions saving ratio results are shown in figure 5.4-8. The EMSR values are closely related to the FESR values, because higher FESR means less fuel input to the system. Comparison of figures 5.4-8(a) and (b) indicates that the EMSR results improve in several industries when power export is allowed. The reasons for this are that the FESR results are improved in those industries with power export and that for power export emissions from the combined-cycle systems are less than those from the coal-fired utilities.

The emissions per million Btu of fuel energy consumption used by the contractors are shown in table 5.4-2. GE assumed higher NO_x emissions from the fuel-bound nitrogen and higher particulate emissions from its coal-derived-residual-fueled system than was assumed for any other combined-cycle system considered by either contractor. This difference is reflected in the relatively low EMSR values for the GE residual-fueled system.

5.4.2.3 Capital Cost

Capital cost estimates for the gas turbine/steam turbine combined-cycle systems are compared in figure 5.4-9(a) for a 10-MW-electric system with recovery of waste heat as 300° F steam. Each contractor estimated the costs according to the cost accounts described in section 4.1. The bar graphs include all costs of equipment and installation for a 10-MW-electric combined-cycle system including all fuel-handling, storage, and heat recovery equipment. Costs of a supplementary boiler and its associated fuel-handling equipment are not included.

Figure 5.4-9(b) shows the capital costs, including a supplementary boiler sized to yield a power-to-heat ratio of 0.25. As indicated in figure 3.2-2 this power-to-heat ratio is near the mean value for all of the processes studied in CTAS. Also shown is a breakdown of capital cost according to the cost categories discussed in section 4.1. The major difference between the GE and UTC residual-fueled systems is in the category 5 cost estimates for supplementary boilers (category 5). This difference does not stem from the difference in supplementary boiler size but is caused by substantially different unit boiler costs per duty used by each contractor.

The two UTC coal-fired systems have about the same capital costs. They are substantially higher than the capital costs for the residual-fueled systems because of higher costs for coal and waste handling (category 1), for the coal-fired boiler (category 2), and for the gas turbine unit of the coal-fired systems (category 3). No capital cost breakdown is available for the GE system with an integrated gasifier, but it is expected that differences among the coal-fired-system capital cost estimates are not significant.

5.4.2.4 Economics

The incremental capital cost versus the levelized annual operating cost saving for the gas turbine/steam turbine combined-cycle systems is plotted for the nine representative industries in figures 5.4-10 and 5.4-11. Also shown in the figures are lines corresponding to constant return on investment. In each figure the origin corresponds to the noncogeneration case, where required power is purchased and onsite steam is produced in a residual-fueled boiler. Since the power requirements of the processes vary considerably (table 4.4-1), the incremental capital cost and levelized annual operating cost saving are expressed per unit of site power required.

Figure 5.4-10 shows that the residual-fueled systems could achieve ROI's equal to or greater than 20 percent in several industries. Those cases with high ROI's require substantially smaller incremental capital costs than the coal-fired systems, and yet they achieve operating cost savings. Both contractor results agree that the residual-fueled, combined-cycle systems could achieve ROI's greater than 15 percent in the chlorine, newsprint, and writing paper (bleached Kraft) industries. GE systems also achieve ROI's greater than 15 percent in other industries. Malt beverage and meat packing, which have lower load factors, did not achieve 15 percent ROI. GE's meat packing case results in no annual operating cost saving because of a low load factor and thus is not shown in the figure. Export cases show lower ROI's because the capital cost increase is more dominant than the effect of the operating cost saving.

Figure 5.4-11 shows that the coal-fired systems have lower ROI's than the residual-fueled systems. Even though the coal-fired systems achieve higher operating cost savings by burning cheaper coal, the substantial increase in their capital costs has a greater effect on ROI results. The UTC combined cycles with AFB and PFB furnaces (figs. 5.4-11(b) and (c)) show exceptionally high ROI's for petroleum. The primary reason for this result is the fuel switching from residual fuel in the noncogeneration case to cheaper coal in the cogeneration case in order to meet the significantly large process direct-heat requirement. NASA did not modify the UTC results because it would involve modification of the UTC energy conversion system, which provides hot gas for some of the process direct-heat requirement. As mentioned in the performance discussion of this section, NASA modified the UTC results for the alumina and integrated steel processes to exclude direct-heat needs. The GE coal-fired system (fig. 5.4-11(a)) achieves higher ROI's in petroleum and alumina than in other representative industries by means of larger operating cost saving even though the GE system has relatively low FESR's in these two industries. The reasons are that these industries have low power-to-heat ratios and thus require large supplementary boilers when power is matched and that GE uses cheaper coal in the cogeneration supplementary boiler but uses residual fuel in the noncogeneration onsite boiler. Note that GE used the same type of fuel

in both the energy conversion system and the supplementary boiler for the cogeneration case. The GE system with an integrated gasifier achieves ROI's greater than 10 percent in the chlorine and newsprint industries. Both UTC systems with the AFB and PFB furnaces achieve ROI's greater than 10 percent in the chlorine, newsprint, and writing paper industries.

The other economic measure calculated in CTAS to combine the effects of capital and operating costs is the percent saving in levelized annual energy cost (LAEC), which is discussed in section 4.3. Figure 5.4-12 shows the LAEC saving ratios for the nine representative industries. Relative attractiveness measured in terms of the LAECSR is in agreement with that found in the ROI results. The newsprint and chlorine processes are attractive in terms of the LAECSR for all subgroups of the gas turbine/steam turbine combined cycles. The writing paper industry is attractive for both contractors' residual-fueled systems. Very high LAECSR's achieved by the coal-fired systems in the petroleum industry are due to the fuel switching pointed out in the discussion of the ROI results. Meat packing, which has a very low load factor, shows no LAEC saving in the GE results and very small LAEC saving in the UTC results. When power export is allowed, some GE cases (fig. 5.4-12(b)) show minor improvement in LAECSR, but the relative attractiveness of industries for the combined-cycle systems remains the same as in the cases with no power export (fig. 5.4-12(a)).

5.4.2.5 Relative National-Basis Fuel Saving

Energy saving aggregated to a national basis is plotted as a function of hurdle ROI in figures 5.4-13 to 5.4-16. The procedure used to evaluate these curves is described in section 4.4. It was assumed that each system would be 100 percent implemented in new-capacity additions or retirement replacements between 1985 and 1990 in each process where the results yield an ROI greater than the hurdle rate shown. Only processes specifically studied by each contractor were considered. These figures are intended to illustrate the comparative potential saving versus ROI requirement, but they are not to be used as an illustration of the absolute magnitude of the savings. Only the results for no-power-export cases are presented in the figures. When power-export cases are included, energy saving by the combined-cycle systems improves because of the increase in FESR, but ROI values drop in most cases because the increase in capital costs for the larger systems needed for export has a greater effect on the ROI results.

Results for the residual-fueled combined-cycle systems are shown in figure 5.4-13. The GE results (fig. 5.4-13(a)) include some import-power cases; GE did not consider match-power strategy if it produced more recoverable heat than required by the process. This situation arises when the site-required power-to-heat ratio is greater than the system power-to-heat ratio. In this case the match-power strategy results in throwing away excess heat produced by the system. Results for the GE system indicate that the potential national energy saving for an ROI hurdle rate of 20 percent is about two-thirds of the saving if no hurdle rate is considered. Results for the UTC system indicate that the potential national energy saving for an ROI hurdle rate of 20 percent is more than a half of the potential saving if no hurdle rate is considered.

Results for the coal-fired combined-cycle systems are shown in figures 5.4-14 to 5.4-16. The coal-fired systems, which achieve lower fuel energy saving than the residual-fueled systems as shown in figure 5.4-7(a), show lower energy saving potential on a national basis than the residual-fueled systems. Large ROI values in the GE petroleum and alumina industries are due to the boiler fuel switching, as explained in the discussion of the economic results. The large ROI for the UTC petroleum case is due to switching from residual fuel in the noncogeneration case to coal in the cogeneration case for the large amount of direct heat, as is also explained in the discussion of the economic results. The large ROI for the UTC styrene process is mainly caused by switching from coal-derived residual fuel in noncogeneration to cheap coal in cogeneration for use in the very large steam boilers required by the styrene process. These large boilers are made necessary by the very low site-required power-to-heat ratio of 0.008 exclusive of the direct-heat requirement. The large ROI of the UTC ethylene process is due to fuel switching from residual oil in noncogeneration to coal in cogeneration for both process direct heat and steam.

5.4.3 Summary

The range of results achieved by the gas turbine/steam turbine combined-cycle systems are presented in table 5.4-3 for a representative subset of nine industries. Where petroleum appears as the most attractive application of the combined-cycle system, the next best application is also listed because the petroleum results, return on investment (ROI) and levelized annual energy saving ratio (LAECSR), are greatly affected by the fuel switching discussed in the preceding section.

Newsprint, chlorine, and writing paper appear to be the as most attractive industries for the combined-cycle subgroups with respect to the fuel energy saving ratio (FESR), LAECSR, emissions saving ratio (EMSR), and ROI.

The FESR results range from negative to a high of 39 percent, and they depend largely on the degree of the system match with the industry site. Industries with low power-to-heat ratios show low FESR's, but their FESR's increase when power export is allowed. The residual-fueled combined-cycle systems operate at higher gas turbine inlet conditions than the coal-fired systems, and they show higher FESR results. The LAECSR results range from negative to 29 percent, excluding the petroleum results. The ROI results range from 5 to 31 percent for the residual-fueled systems and from 4 to 50 percent for the coal-fired systems. Economic results do not show any improvement when power export is allowed.

The EMSR results range from negative to 66 percent. The lower GE results are due to the high NO_x emissions assumed.

The two most attractive industries among the nine representative industries for the residual-fueled combined-cycle systems are chlorine and newsprint. In these two industries both contractors' residual-fueled systems achieve FESR and ROI greater than 20 percent and LAECSR and EMSR greater than 15 percent. The contractors' coal-fired systems achieve lower FESR and ROI values in the chlorine and newsprint industries than the residual-fueled, combined-cycle systems. Among the nine representative industries, however, these two industries are the most attractive for the coal-fired systems, except

for the petroleum industry, in which the economic result was greatly affected by fuel switching for direct heat.

Power requirements in the meat packing, malt beverage, and nylon industries may be too low to use combined cycles unless power-export cases are considered. This is especially true for the use of the GE combined cycle with an integrated gasifier for these small industries.

Only a limited number of system options could be explored as part of this study. One option not examined in CTAS is a coal-gasifier combined cycle in which part of the fuel gas is used directly for heating or is made into another useful form such as methanol. This combined-cycle option has the potential for higher FESR and better economics, particularly for industries with low power-to-heat ratios.

TABLE 5.4-1. - ENERGY CONVERSION SYSTEM PARAMETERS AND CONFIGURATIONS STUDIED FOR GAS TURBINE/STEAM TURBINE COMBINED-CYCLE SYSTEMS

Parameter	General Electric Co.	United Technologies Corp.
Common to all subgroups		
Type of steam turbine	Back pressure noncondensing	Nonextraction condensing
Type of process steam (fig. 5.5-1)	Exhaust steam from steam turbine	Steam from heat-recovery steam generator
State-of-the-art combined cycle using petroleum distillate fuel		
Type of fuel	------------------	Petroleum distillate
Gas turbine inlet temperature, °F	------------------	2000
Pressure ratio	------------------	14
Size range, MW	------------------	10-150
System power-to-heat ratio	------------------	2.08
Combined cycle using residual fuel		
Type of fuel	Petroleum and coal-derived residual	Petroleum and coal-derived residual
Gas turbine inlet temperature, °F		
With air cooling	2200	2500
With water cooling	2600	------------------
Pressure ratio:		
With air cooling	8, 12, 16	18
With water cooling	16	------------------
Throttle condition, psia/°F	1465/865	------------------
Size range, MW	14-196	10-150
System power-to-heat ratio:		
Design option 1	[a]0.7-1.4	4.3
Design option 2	[a]0.7-1.4	2.1
Design option 3	[a]0.7-1.4	[b]1.3
Combined cycle with atmospheric fluidized bed		
Type of fuel	------------------	Coal
Gas turbine inlet temperature, °F	------------------	1500
Pressure ratio	------------------	10
Size range, MW	------------------	10-150
Design option 1:		
Process steam from-	------------------	Heat-recovery steam generator
Power-to-heat ratio		0.63
Design option 2:		
Process steam from-	------------------	Steam tubes in AFB convection space
Power-to-heat ratio	------------------	0.56

TABLE 5.4-1. - Concluded.

Combined cycle with pressurized fluidized bed		
Type of fuel	-------------------	Coal
Gas turbine inlet temperature, °F	-------------------	1600
Pressure ratio	-------------------	10
Size range, MW	-------------------	10-150
Combined cycle with integrated gasifier		
Type of fuel	Coal	-------------------
Gas turbine inlet temperature (with water cooling) °F	2100	-------------------
Pressure ratio	12	-------------------
Type of steam turbine	Back pressure noncondensing	-------------------
Throttle condition, psia/°F	1465/1000	-------------------
Type of gasifier	Entrained-bed, oxygen-blown Texaco	-------------------
Size range, MW	80-500	-------------------

[a]Design options apply only to UTC system. They are achieved by varying the steam extraction ratio from the heat-recovery steam generator.
[b]Fig. 5.4-5.

TABLE 5.4-2. - EMISSIONS FOR GAS TURBINE/ STEAM TURBINE COMBINED-CYCLE SYSTEMS

(a) Coal-derived-residual-fueled systems

Pollutant	General Electric Co.	United Technologies Corp.
	Emissions, $lb/10^6$ Btu	
Oxides of sulfur	0.80	0.82
Oxides of nitrogen	1.20	.50
Particulates	.513	.10

(b) Coal-fired systems

Integrated-gasifier system		
Oxides of sulfur	1.2	---
Oxides of nitrogen	.7	---
Particulates	.1	---
Atmospheric-fluidized-bed system		
Oxides of sulfur	---	1.2
Oxides of nitrogen	---	.2
Particulates	---	.001
Pressurized-fluidized-bed system		
Oxides of sulfur	----	1.2
Oxides of nitrogen	----	.2
Particulates	----	.10

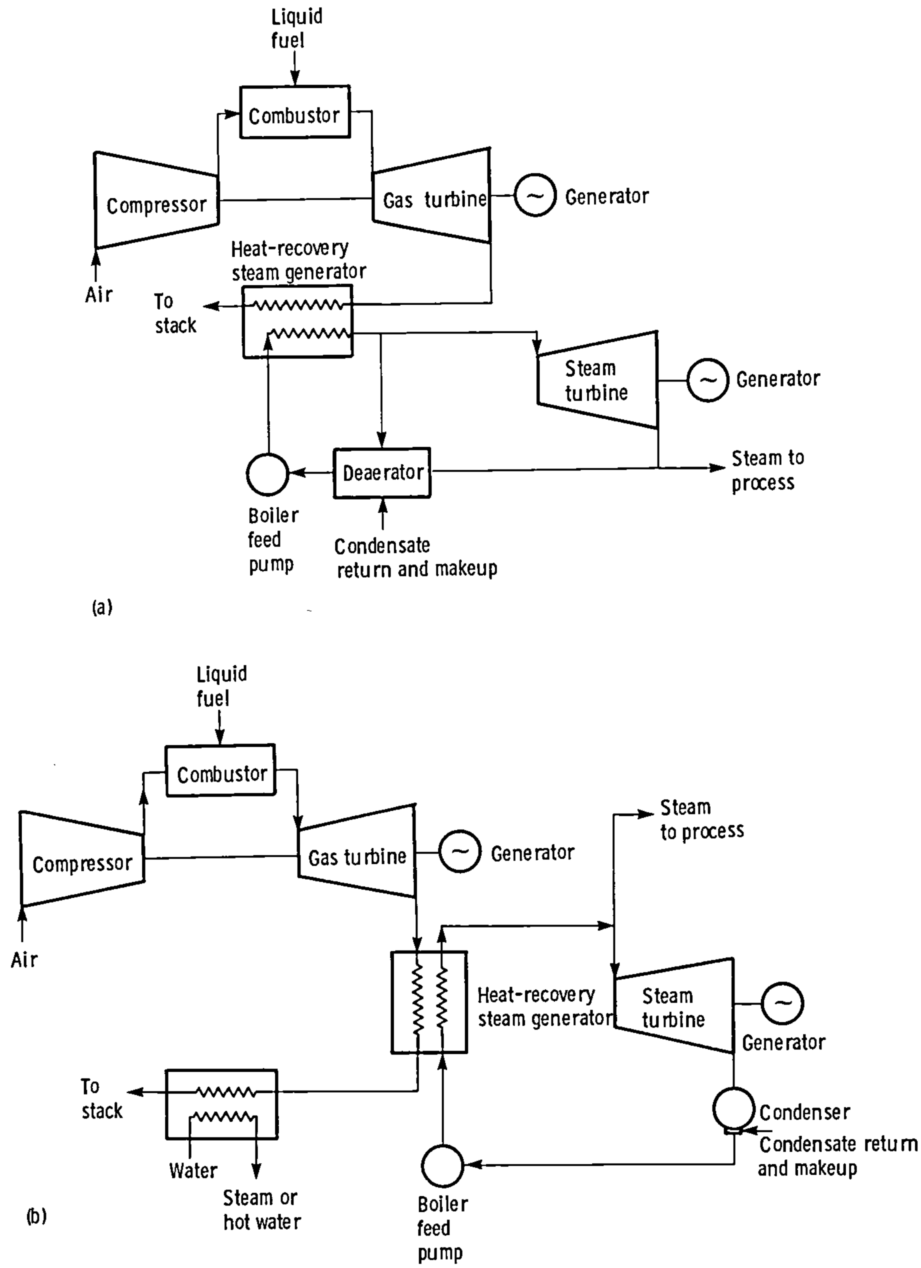
TABLE 5.4-3. - RANGE OF RESULTS FOR GAS TURBINE/STEAM TURBINE COMBINED-CYCLE SYSTEMS USED WITH NINE REPRESENTATIVE INDUSTRIES

(a) No power export allowed

Energy conversion system subgroup	Contractor	Fuel energy saving ratio, FESR	Industry with maximum FESR	Emissions saving ratio, EMSR	Industry with maximum EMSR	Levelized annual energy cost, LAEC	Industry with maximum LAEC	Return on investment, ROI, percent	Industry with maximum ROI
State-of-the-art combined cycle/distillate	UTC	0-28	Chlorine	Negative to 1	Chlorine	7-63	Chlorine	Negative to 6	Chlorine
Combined cycle/residual	GE	11-32	Newsprint	6-22	Chlorine	5-24	Writing paper	20-31	Chlorine
	UTC	5-39	Chlorine	Negative to 27	Chlorine	7-58	Chlorine	5-31	Chlorine
Combined cycle/AFB	UTC	Negative to 23	Newsprint	10-36 [a]25	Petroleum; writing paper	4-41	Newsprint	7-50 [a]15	Petroleum
Combined cycle/PFB	UTC	2-28	Newsprint; chlorine	3-36 [a]28	Petroleum; newsprint	5-48	Chlorine	10-50+ [a]77	Petroleum; writing paper
Combined cycle/integrated gasifier	GE	3-17	Chlorine	4-27 22	Petroleum; alumina	Negative to 15	Chlorine	7-19	Petroleum

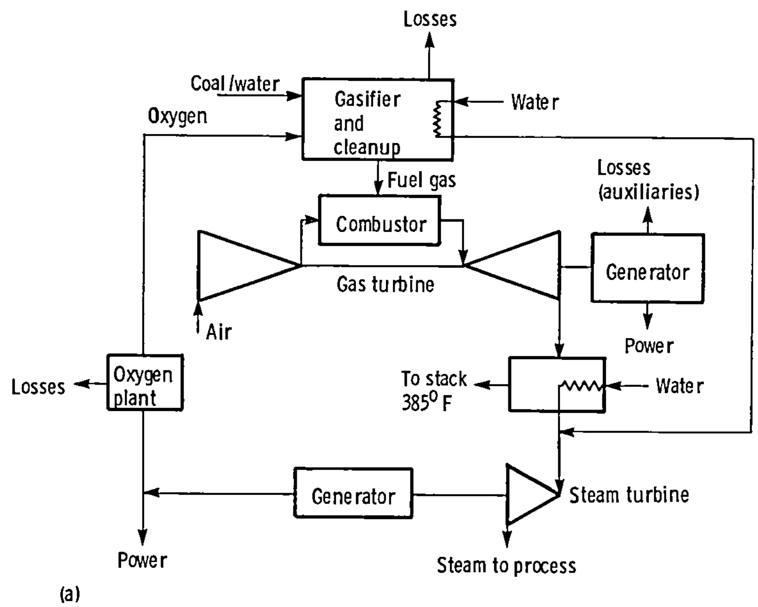
(b) Power export allowed

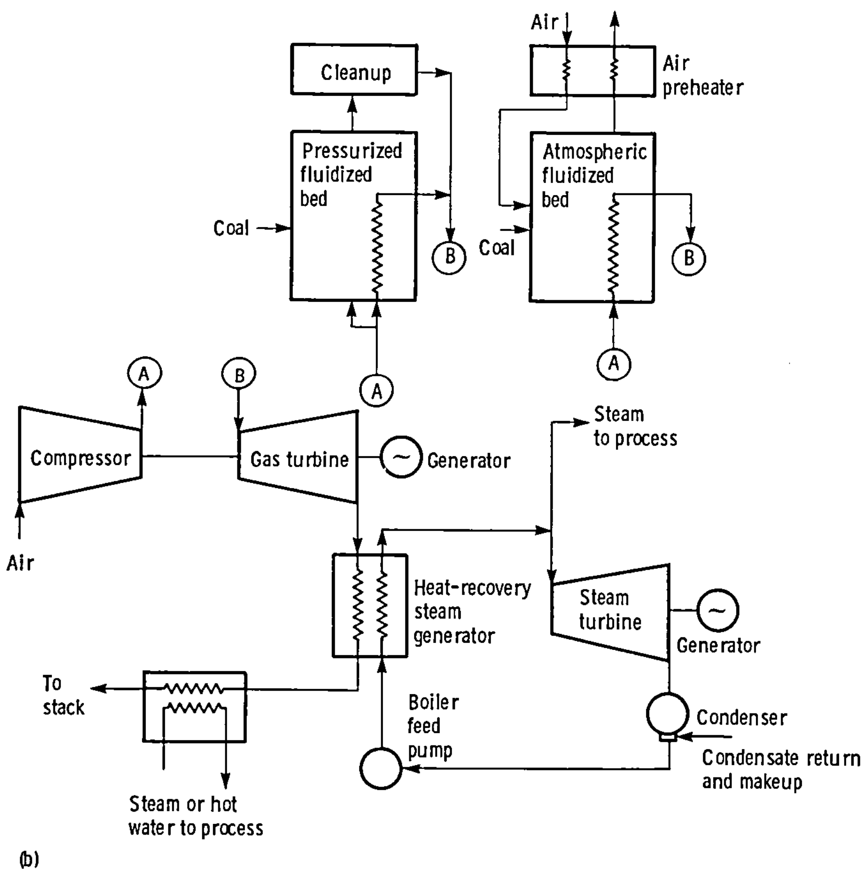
Energy conversion system subgroup	Contractor	Fuel energy saving ratio, FESR	Industry with maximum FESR	Emissions saving ratio, EMSR	Industry with maximum EMSR	Levelized annual energy cost, LAEC	Industry with maximum LAEC	Return on investment, ROI, percent	Industry with maximum ROI
State-of-the-art combined cycle/distillate	UTC	0-29	Chlorine	Negative to 1	Chlorine	7-66	Chlorine	Negative to 6	Chlorine
Combined cycle/residual	GE	11-37	Writing paper	5-29	Writing paper	5-26	Writing paper	8-31	Chlorine
	UTC	5-39	Chlorine	Negative to 27	Chlorine	7-58	Chlorine	5-31	Chlorine
Combined cycle/AFB	UTC	Negative to 24	Newsprint	Negative to 37 [a]25	Petroleum; writing paper	4-41	Newsprint	5-50 [a]15	Petroleum; writing paper
Combined cycle/PFB	UTC	2-28	Newsprint; chlorine	3-37 [a]28	Petroleum; newsprint	5-48	Chlorine	4-50+ [a]77	Petroleum; writing paper
Combined cycle/integrated gasifier	GE	3-27	Newsprint	4-35	Petroleum	Negative to 24	Newsprint	7-19	Petroleum



(a) GE.
(b) UTC.

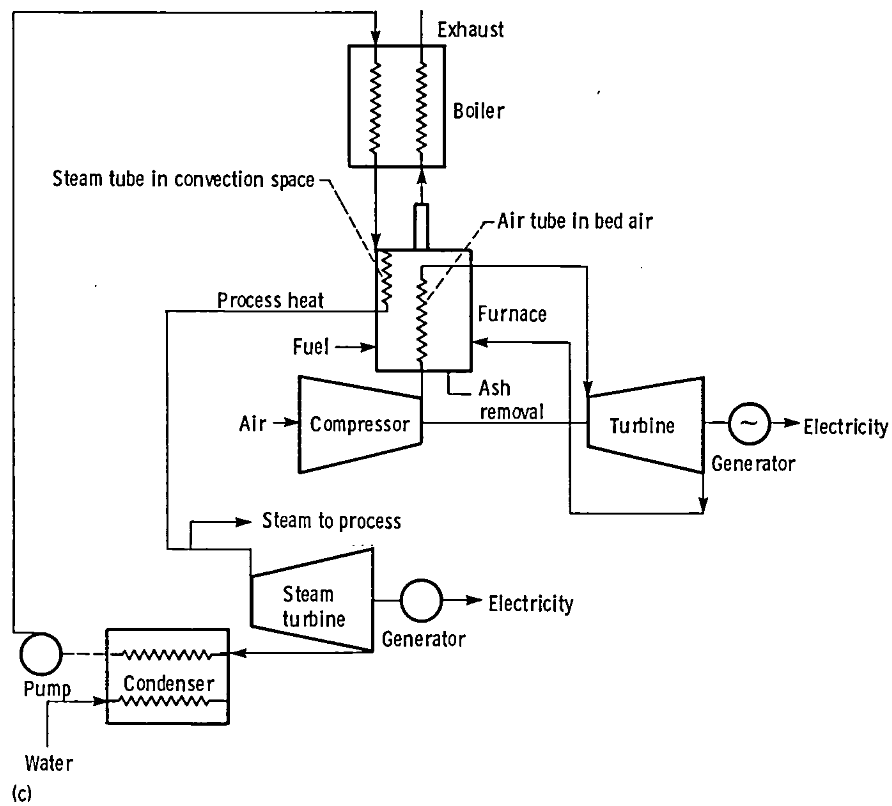
Figure 5.4-1. - Schematics of residual-fueled gas turbine/steam turbine combined-cycle systems.





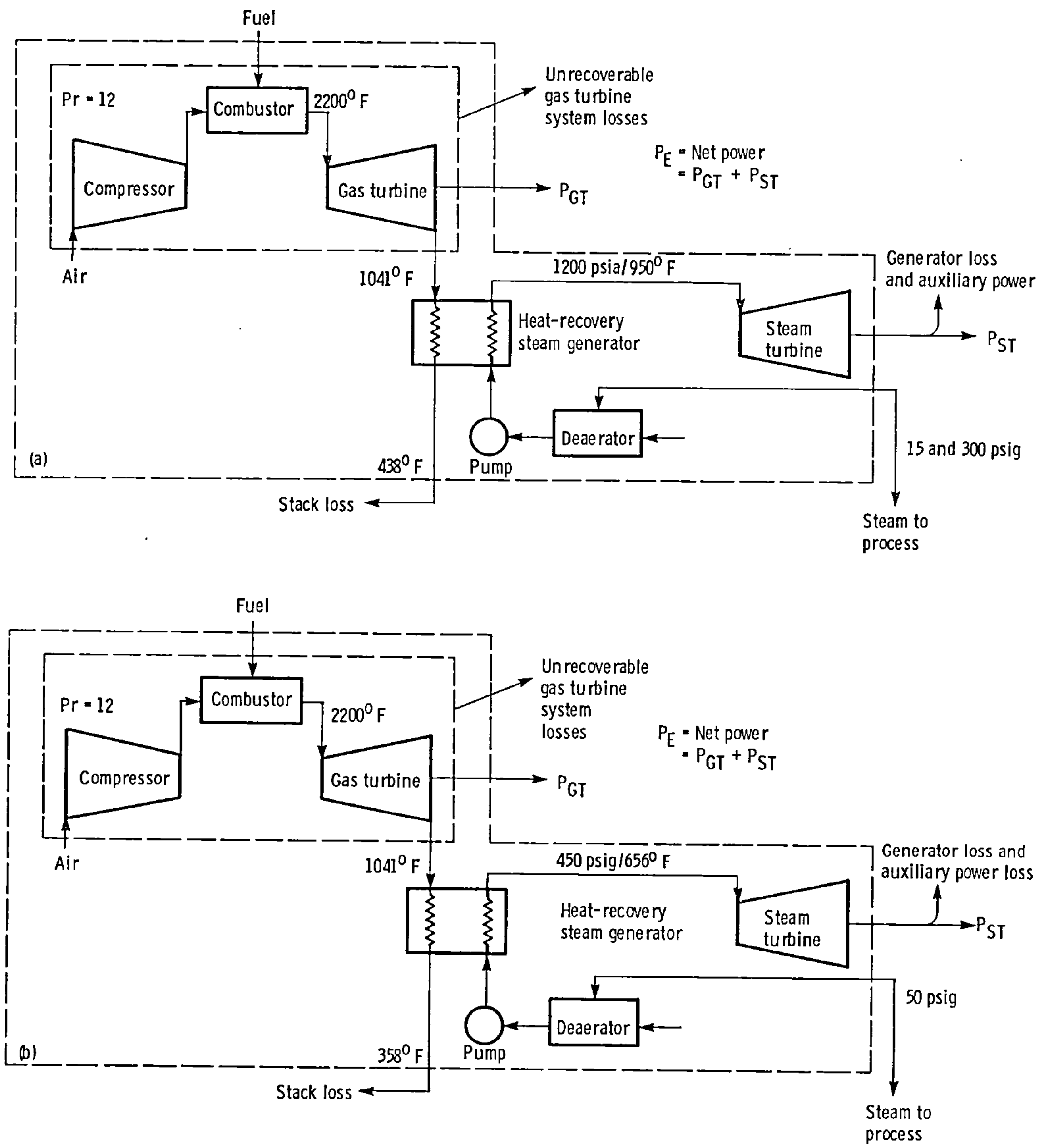
(a) GE system with integrated gasifier.
(b) UTC system.

Figure 5.4-2. - Schematics of coal-fired gas turbine/steam turbine combined-cycle systems.



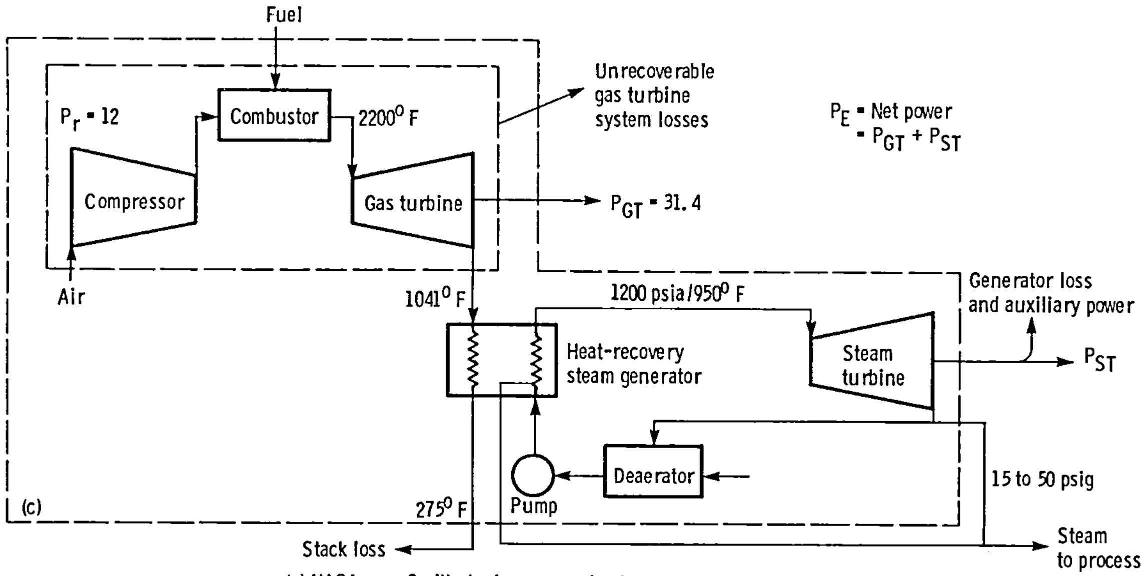
(c) Alternative configuration of UTC's atmospheric fluidized bed system.

Figure 5.4-2. - Concluded.



(a) NASA case 1.
(b) NASA case 2 with lower steam throttle position.

Figure 5.4-3. - Configurations and parameters used to examine cogeneration performance characteristics of combined-cycle systems.



(c) NASA case 3 with dual-pressure heat-recovery steam generator.

Figure 5.4-3. - Concluded.

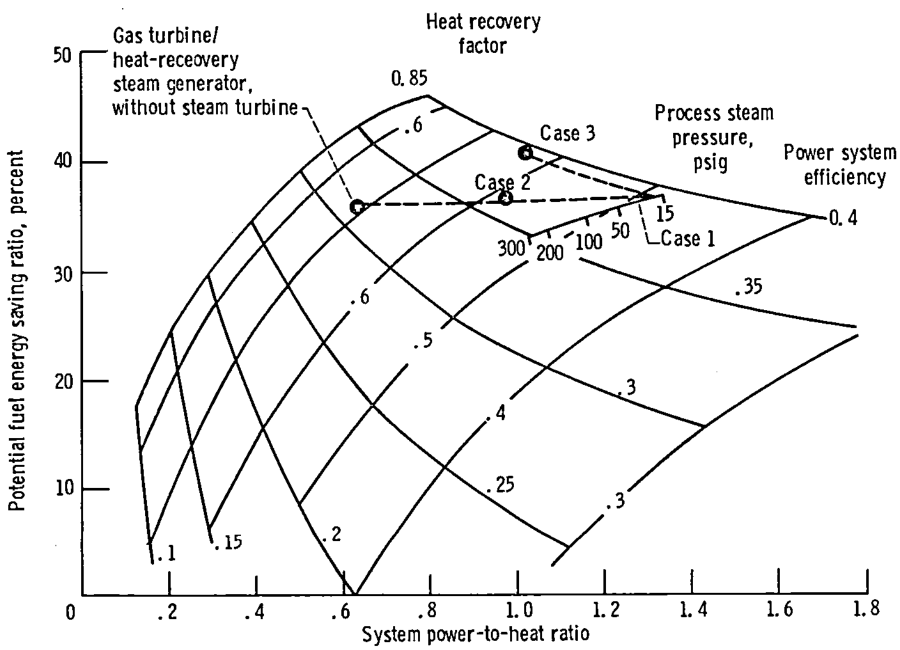


Figure 5.4-4. - Performance characteristics of gas turbine/steam turbine combined cycle systems from NASA example cases. For nongeneration case: boiler efficiency, 85 percent; utility power efficiency, 32 percent.

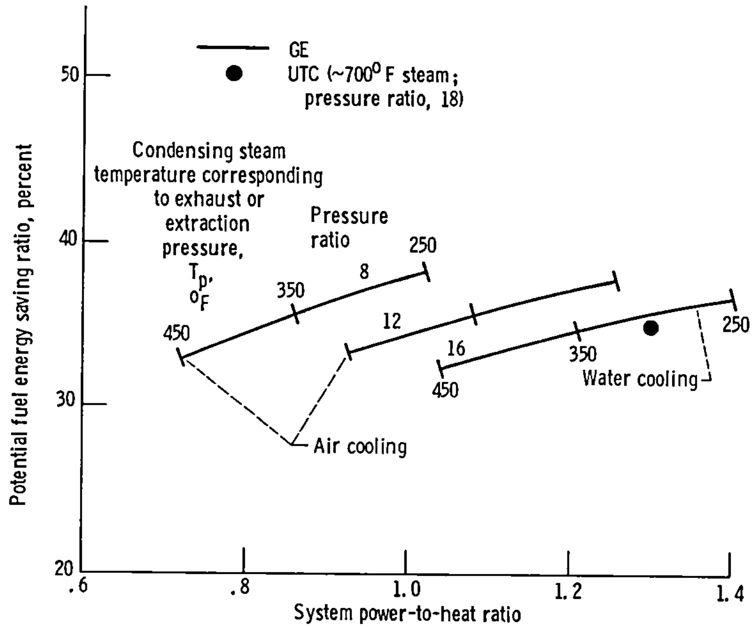


Figure 5.4-5. - Potential fuel energy saving ratios for residual-fueled gas turbine/steam turbine combined-cycle systems.

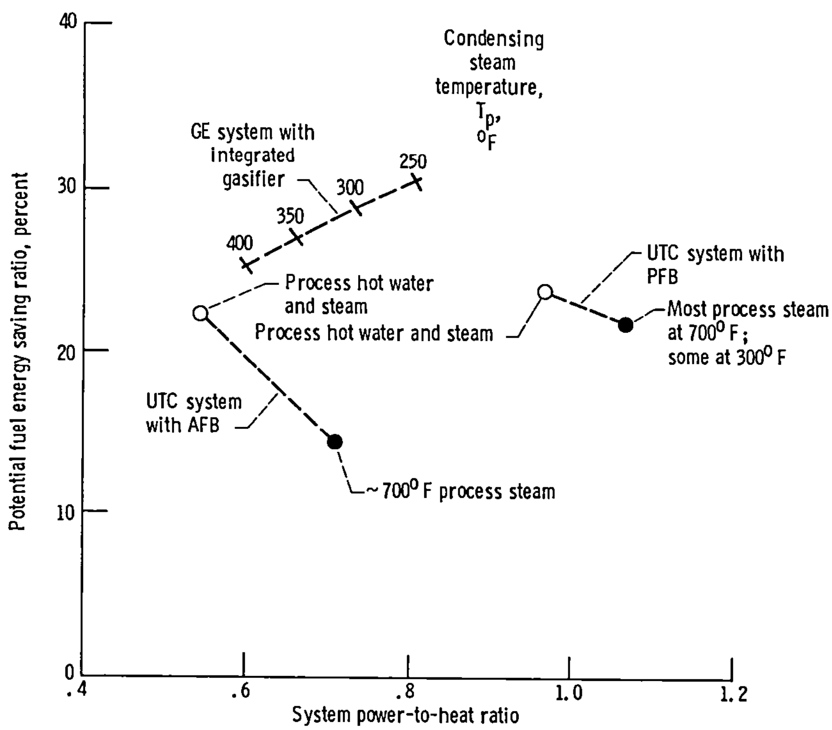
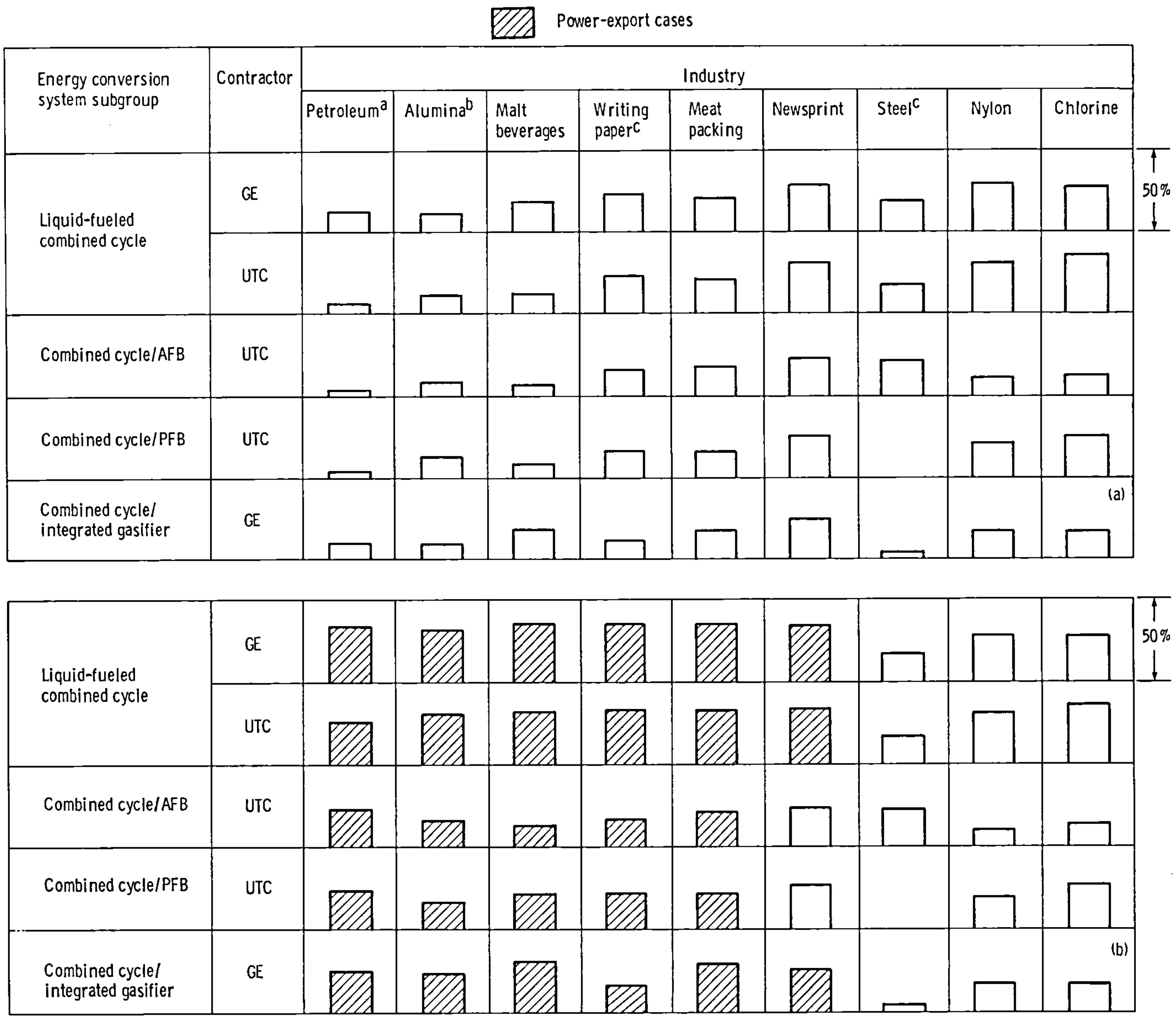


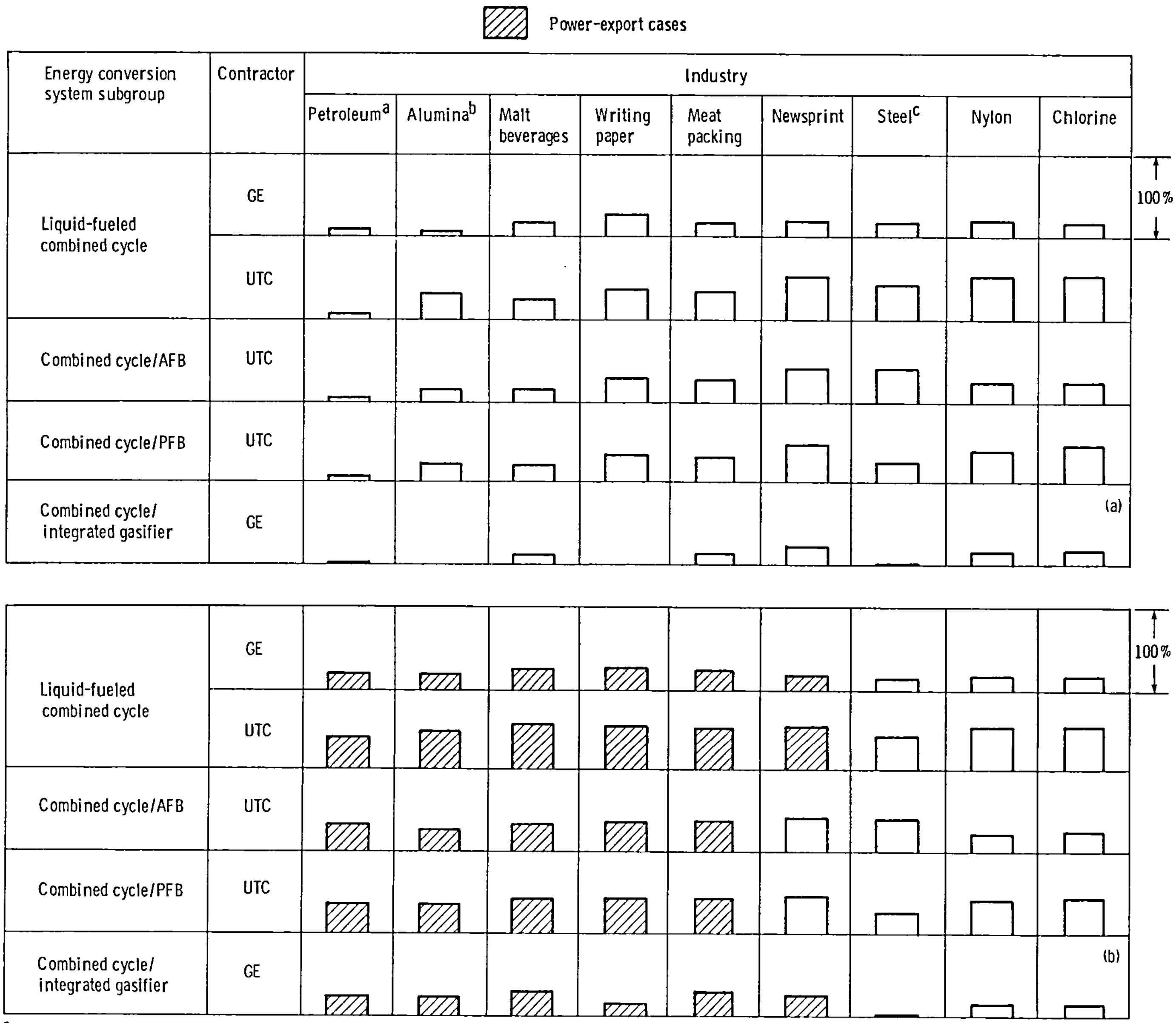
Figure 5.4-6. - Potential fuel energy saving ratios for coal-fired gas turbine/steam turbine combined-cycle systems.



[a] UTC combined cycles provided hot gas for a part of direct heat required by petroleum refining. Process steam was provided by supplementary boiler only.
[b] NASA modified UTC results to delete direct-heat supply with specified clean fuel.
[c] NASA modified UTC results to delete direct-heat requirement. NASA used byproduct fuel in steam boilers but did not use it in the combined cycles.

(a) No power export allowed.
(b) Power export allowed.

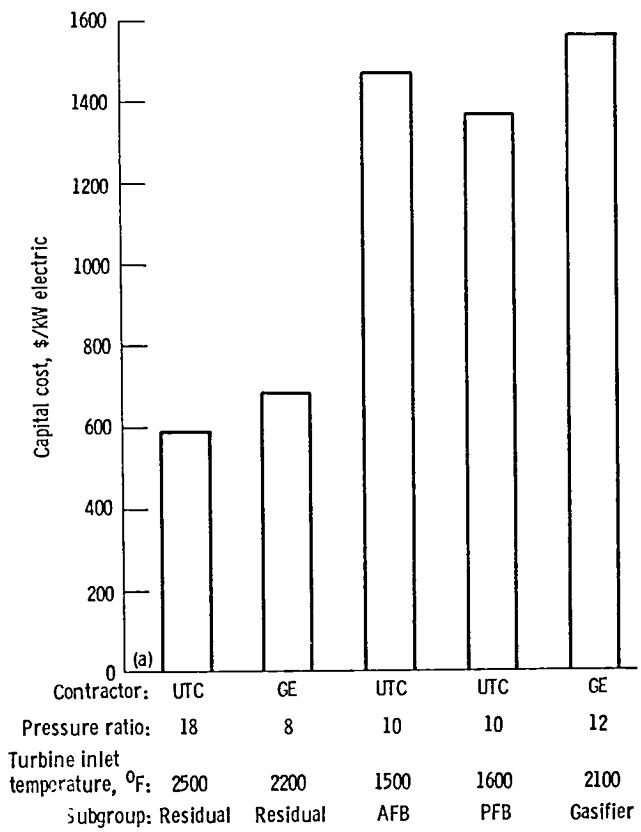
Figure 5.4-7. - Fuel energy saving ratios for gas turbine/steam turbine combined-cycle systems. (Blanks denote all negative values.)



[a] UTC combined cycles provided hot gas for a part of direct heat required by petroleum refining. Process steam was provided by supplementary boiler only.
[b] NASA modified UTC results to delete direct-heat supply with specified clean fuel.
[c] NASA modified UTC results to delete direct-heat requirement. NASA used byproduct fuel in steam boilers but did not use it in the combined cycles.

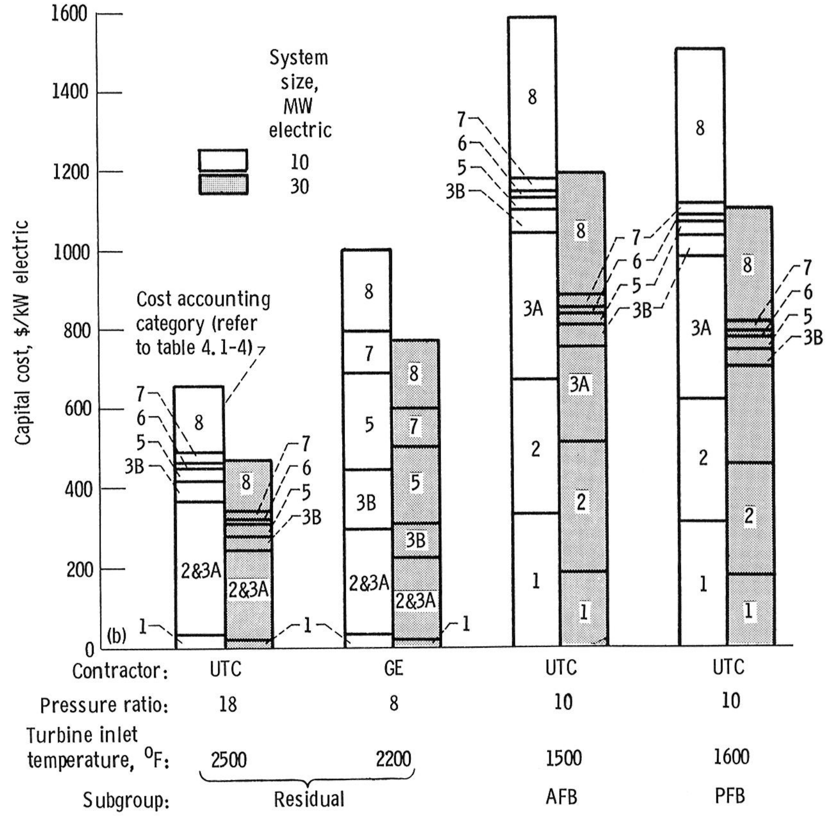
(a) No power export allowed.
(b) Power export allowed.

Figure 5.4-8. - Emissions saving ratios for gas turbine/steam turbine combined-cycle systems. (Blanks denote all negative values.)



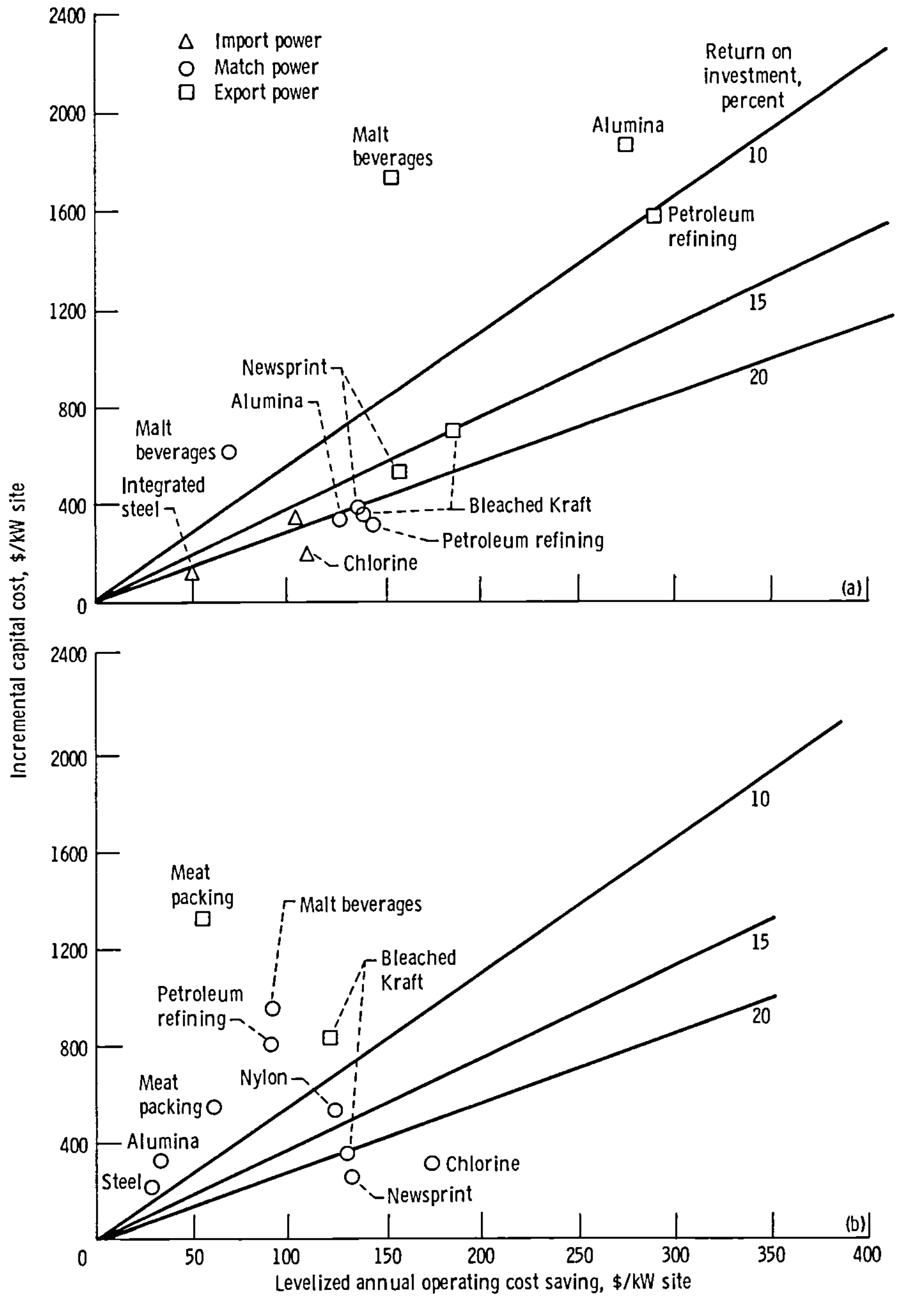
(a) 10-MW electric systems without supplementary boilers.

Figure 5.4-9. - Capital costs for gas turbine/steam turbine combined-cycle systems. Process steam temperature, 300° F.



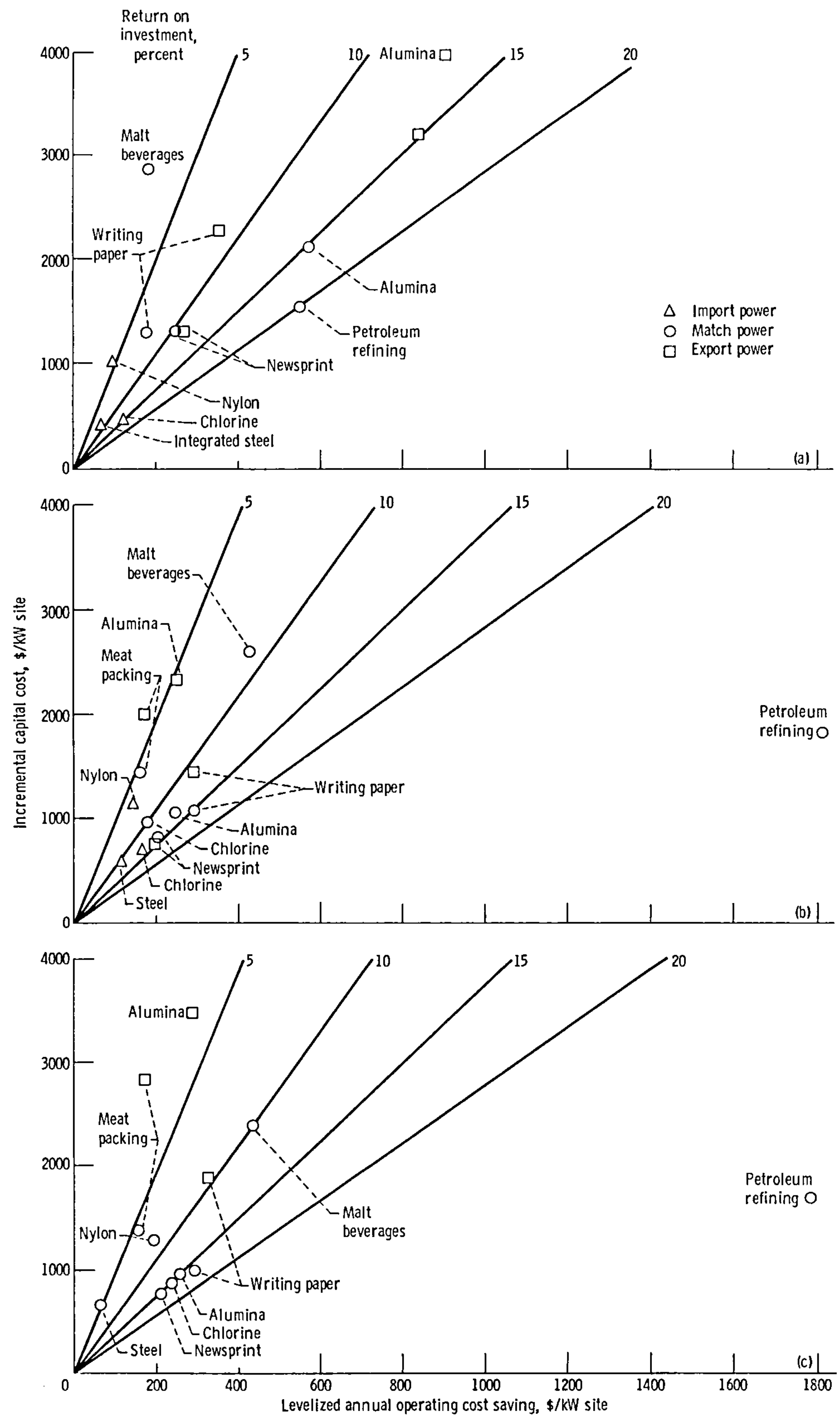
(b) 10- and 30-MW electric systems with supplementary boilers to provide 0.25 power-to-heat ratio.

Figure 5.4-9. - Concluded.



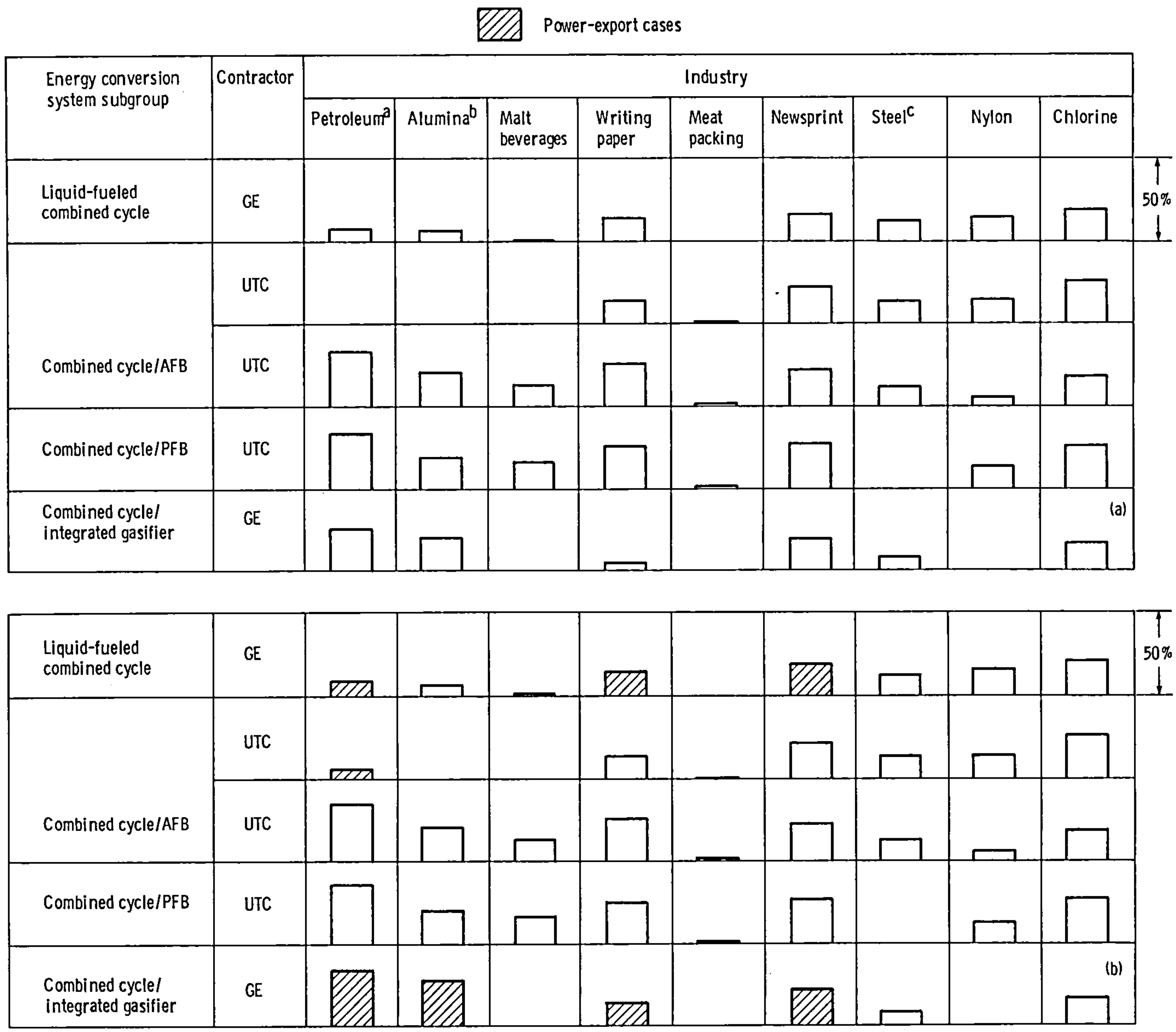
(a) GE.
(b) UTC.

Figure 5.4-10. - Incremental capital cost as a function of levelized annual operating cost saving for residual-fueled gas turbine/steam turbine combined-cycle systems.



(a) GE system with integrated gasifier.
(b) UTC system with AFB furnace.
(c) UTC system with PFB furnace.

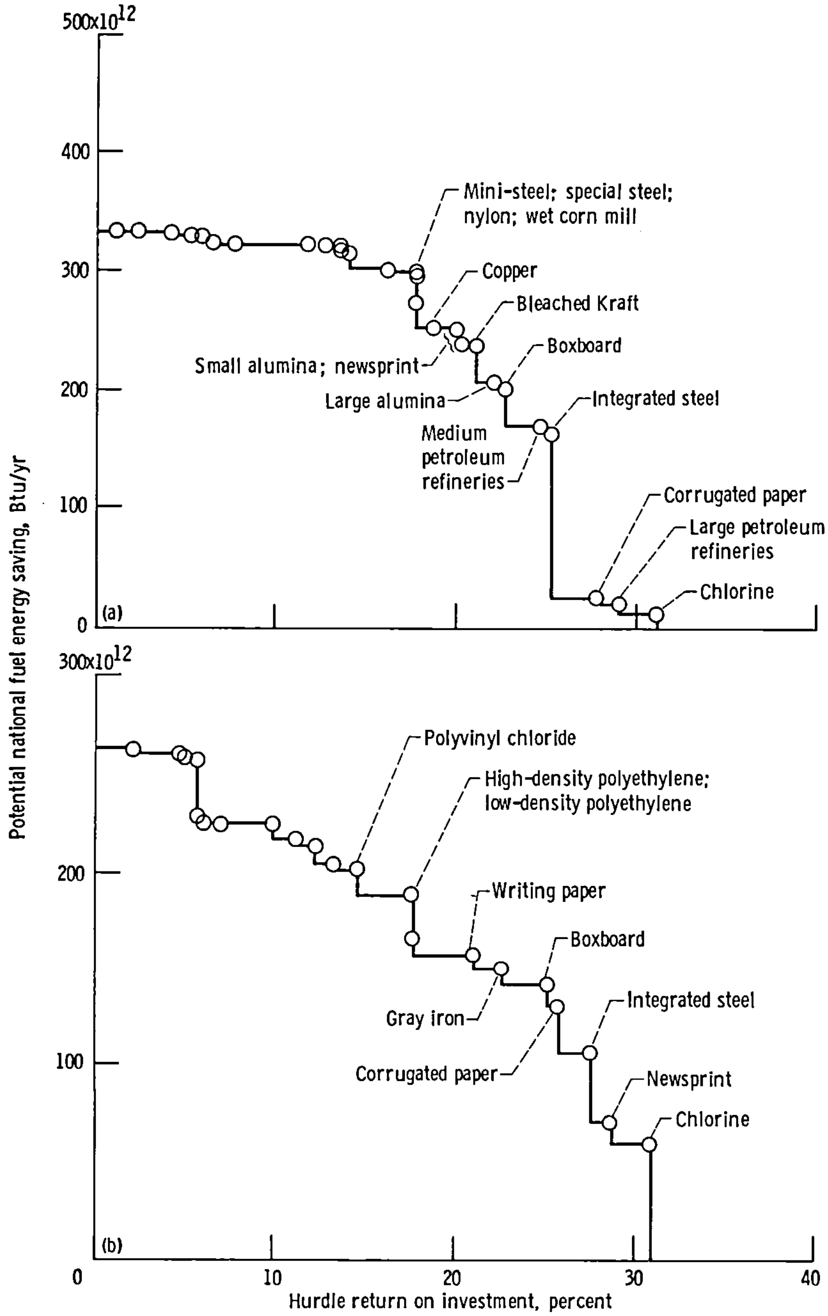
Figure 5.4-11. - Incremental capital cost as a function of levelized annual operating cost saving for coal-fired gas turbine/steam turbine combined-cycle systems.



[a] UTC combined cycles provided hot gas for a part of direct heat required by petroleum refining. Process steam was provided by supplementary boiler only.
[b] NASA modified UTC results to delete direct-heat supply with specified clean fuel.
[c] NASA modified UTC results to delete direct-heat requirement. NASA used byproduct fuel in steam boilers but did not use it in combined cycles.

(a) No power export allowed.
(b) Power export allowed.

Figure 5.4-12. - Levelized annual energy cost saving ratio for gas turbine/steam turbine combined-cycle systems (Blanks denote all negative values.)



(a) GE (no power export).
(b) UTC (match power).

Figure 5. 4-13. - Potential national fuel energy saving as a function of hurdle return on investment for residual-fueled gas turbine/steam turbine combined-cycle systems.

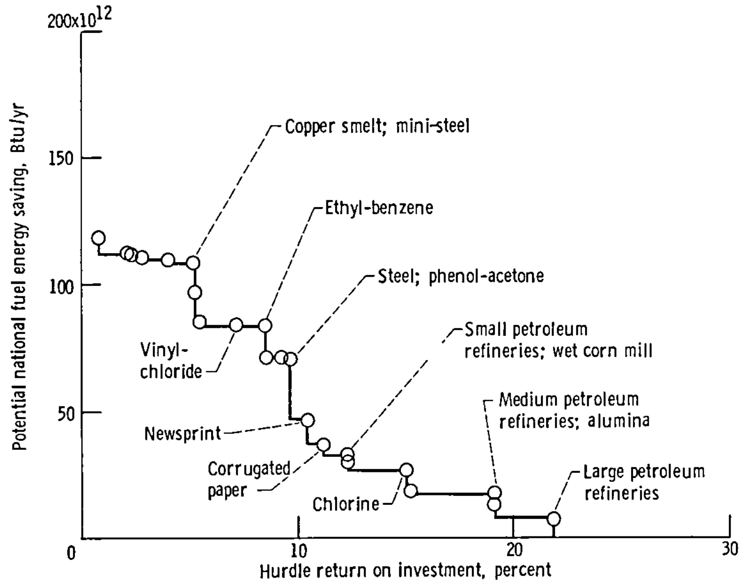


Figure 5.4-14. - Potential national fuel energy saving as a function of hurdle return on investment for GE gas turbine/steam turbine combined cycle/integrated gasifier systems. (Match power.)

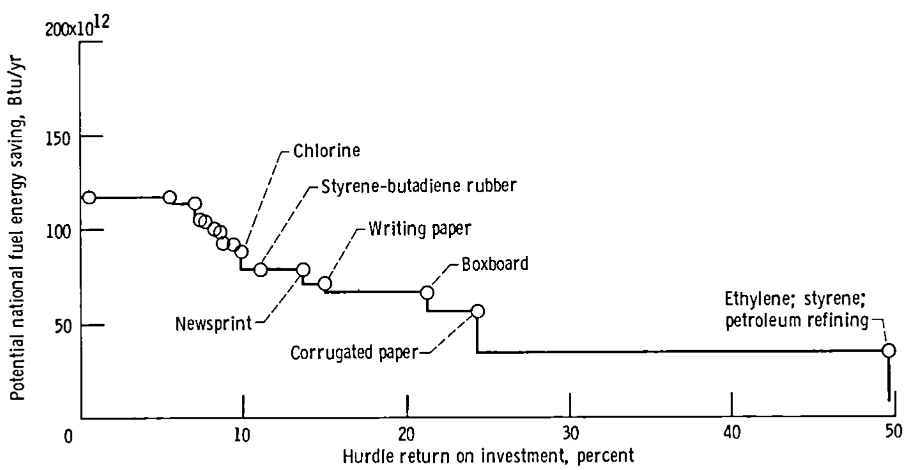


Figure 5.4-15. - Potential national fuel energy saving as a function of hurdle return on investment for UTC's gas turbine/steam turbine combined cycle/AFB system. (Match power.)

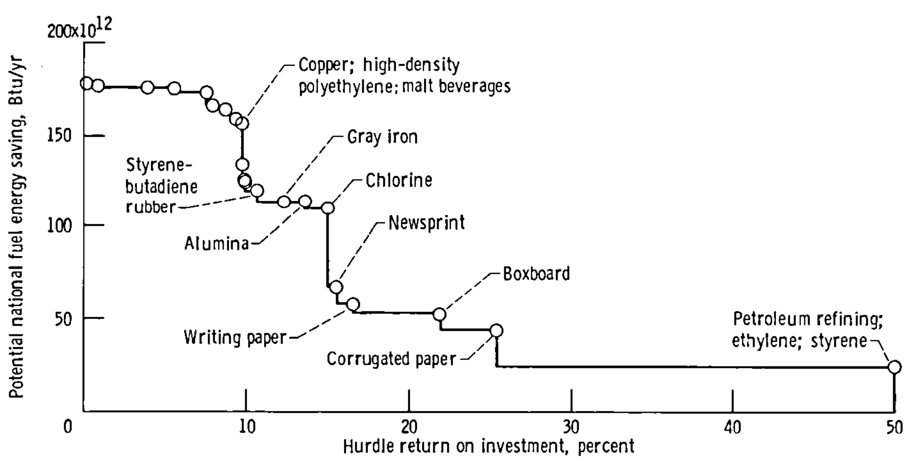


Figure 5.4-16. - Potential national fuel energy saving as a function of hurdle return on investment for UTC's gas turbine/steam turbine combined cycle/PFB system. (Match power.)

5.5 STIRLING ENGINE SYSTEMS

Joseph J. Nainiger

5.5.1 Configurations and Parameters

The design parameters considered by each contractor are shown in table 5.5-1. Both contractors selected coal-fired and liquid-fueled Stirling engines. Helium is used as the working fluid.

The General Electric Stirling engine has a maximum working-fluid temperature of 1390° F for the coal-fired and liquid-fueled cases. The United Technologies Stirling engine has maximum working-fluid temperatures of 1450° F for the coal-fired cases and 1600° F for the liquid-fueled cases.

Schematics for the coal-fired Stirling engine systems of GE and UTC are shown in figures 5.5-1(a) and (b). General Electric selected a pulverized-coal furnace with flue gas desulfurization (FGD) and an intermediate helium-gas heat transfer loop between the furnace and the Stirling engine heater heads. The GE Stirling engine has a single heat input at the maximum working-fluid temperature. Steam is generated or hot water is heated at two places. Heat is rejected from the engine and transferred from the engine working fluid to a cooling-water loop, which then transfers the heat to make process steam or to heat water in a separate heat exchanger. The heat rejection temperature is varied to allow the generation of steam or hot water at the various process temperature requirements. Thus the engine electrical efficiency and the power-to-heat ratio vary considerably with the process temperature requirements. UTC selected an atmospheric fluidized bed with in-bed desulfurization by means of a limestone sorbent and an intermediate helium-gas heat transfer loop between the bed and the Stirling engine heater heads. UTC studied heat addition at two temperature levels. Between the high- and low-temperature heat inputs, process steam is generated by heat input from the helium gas loop. UTC used two design options: one in which the engine electrical efficiency is high, and one in which more steam is generated by heat from the helium loop than is input to the engine. In the UTC system the working-fluid heat rejection temperature is held constant and only water is heated by the heat rejected from the engine. This heat is recovered with a heat exhanger between the helium working fluid and the process water. Therefore for UTC the engine electrical efficiency does not vary with process temperature requirements.

Schematics of the contractors' Stirling systems using liquid fuels are shown in figures 5.5-1(c) and (d). For UTC the same configuration as was shown for the coal-fired systems is used for the liquid-fueled cases. The atmospheric-fluidized-bed (AFB) furnace is replaced by a residual-fueled furnace, and the maximum helium-working-fluid temperature is increased to 1600° F. The higher maximum helium temperature was assumed to be obtainable by using ceramic materials in the furnace heat exchanger. Two design options were considered: one with a high electrical efficiency, and another with lower efficiency and more generation of process steam from heat in the intermediate helium loop. For the liquid-fueled GE case the separate furnace with a helium heat transfer loop is replaced by a furnace or combustor with the engine heater heads directly within it.

5.5.2 Cogeneration System Performance

5.5.2.1 Fuel Energy Saving Ratio

The cogeneration fuel energy savings that would be achieved if the power-to-heat ratio matched the process needs are shown in figure 5.5-2. As discussed in appendix D, if the required power-to-heat ratio differs from the value provided by the energy conversion system, the fuel savings in most cases will be lower. Only if the process requires a power-to-heat ratio lower than that produced by the system and a match-heat - export-power strategy is used will the fuel energy saving ratio equal the value shown in this figure. The "hot water" points represent cogeneration performance if the process requirement is assumed to be only hot water. The coal-fired systems are shown in figure 5.5-2(a) and the residual-fueled systems, in part (b).

UTC design option 1 is characterized by a relatively high electrical efficiency. This is accomplished by removing only a small portion of the heat from the intermediate heat transfer loop for process steam production. This allows more heat to be input to the engine. Design option 2 differs in that more heat is removed from the helium heat transfer loop to generate process steam. The power-to-heat ratio produced by design option 2 is thus much lower. If a process requires only steam (i.e., no hot water), this configuration results in no heat recovery from the engine working-fluid waste heat. In such a case, design option 1 produces a very high power-to-heat ratio, much larger than required by most of the processes studied. When using this design option in a match-power strategy for most processes, it is therefore necessary to use a supplementary boiler. Actually, UTC assumed that the AFB furnace would be sized to produce the additional steam. This is thermodynamically equivalent to using a supplementary boiler and, as shown in appendix D, produces a lower power-to-heat ratio and results in a lower fuel energy saving. Using this approach with design option 1 to match processes with lower power-to-heat ratios resulted in higher fuel energy savings than design option 2 over a wide range of process power-to-heat ratio needs. Thus design option 1 was most often employed.

Most of the process heat from the GE system is recovered from the Stirling engine rejected heat (fig. 5.5-1(a)). As the process steam temperature requirement is increased, the design helium heat rejection temperature must also be increased. This results in a decrease in electrical efficiency and thus decreases in fuel energy saving and power-to-heat ratio, as shown in figure 5.5-2. When only hot water is required, the heat rejection temperature is lower and this results in higher values of electrical efficiency, potential fuel energy saving, and power-to-heat ratio.

For the residual-fueled UTC cases shown in figure 5.5-2(b) the maximum working-fluid temperature is higher than for the coal-fired cases. Also, the amount of heat removed from the intermediate helium heat transfer loop to generate process steam is higher than for the coal-fired cases. Thus the electrical efficiency is only slightly higher than for the coal-fired cases, but the power-to-heat ratio is lower. GE assumed the same system performance for both their coal-fired and residual-fueled systems.

Fuel energy saving ratio (FESR) results for Stirling systems matched to the nine representative industries are shown in figure 5.5-3. The characteristics of these processes are listed in section 3.2. The processes are listed

in figure 5.5-3 in ascending order of power-to-heat ratio. Only matching strategies that produce no excess power are included in figure 5.5-3(a). All matching strategies are included in figure 5.5-3(b). The one that yields the highest FESR was used for this figure. In part (a), where export is excluded, the fuel savings shown are generally most attractive for those processes that require a power-to-heat ratio near that produced by the system. This corresponds to the processes in the middle columns for the GE configuration, shown in figure 5.5-2, yielding power-to-heat ratios in the range 0.3 to 0.6. For the UTC configuration the design option that yielded a high value of power-to-heat ratio was used, and hence the processes that show the highest fuel energy savings in figure 5.5-3(a) are generally those in the columns to the right. The fuel energy saving results obtained for these nine processes when export of power is allowed are shown in figure 5.5-3(b). The FESR results are improved over those in part (a) in many cases where using a larger power system and making excess power result in a greater amount of heat recovery for process use. The cases that involve export are crosshatched; the others correspond to match-power or import situations and are the same as in part (a). The lower the site-required power-to-heat ratio as compared with that produced by the system, the greater the amount of excess power produced in a match-heat strategy. This will affect the economic results as illustrated in later figures and parametrically in appendix D. Since the UTC engine configuration produces a higher power-to-heat ratio (fig. 5.5-2), the amount of export power is generally greater for UTC systems.

In figure 5.5-3(b) the processes yielding the highest FESR are meat packing and malt beverages for the GE cases and meat packing for UTC. These are the cases that require hot water for process use in addition to steam and therefore result in the most heat recovery with the least effect on Stirling engine efficiency. The significant improvement in cogeneration performance potential for the Stirling engine when heat is recovered as hot water is indicated in figure 5.5-2.

5.5.2.2 Emissions Saving Ratio

The emissions saving ratio for the Stirling systems matched to the nine representative industrial processes is shown in figure 5.5-4. The emissions saving ratio, defined in section 2.5, is the percentage reduction in emissions when both the utility site and the industrial site are considered. The results shown in figure 5.5-4 correspond to the total of NO_x, SO_x, and particulate emissions and are calculated for the use of coal-derived residual fuel in the noncogeneration onsite boiler and coal at the utility. In addition to the amount of fuel saved, the emissions saving depends strongly on the combustion characterisitcs of the system and the type of fuel used. The emissions per unit of fuel consumed are shown in table 5.5-2 for each contractor's systems. The emissions saving ratios are obviously highest for the system using coal-derived distillate fuel in figure 5.5-4 because of the lower emissions rates as shown in table 5.5-2. For the coal-fired cases the estimates for SO_x and particulates are the same, but the NO_x estimates for UTC's atmospheric fluidized bed (AFB) are substantially lower than those for GE's pulverized furnace with flue gas desulfurization (FGD). As a result the emissions saving ratios for the UTC coal-fired cases in figure 5.5-4 are generally higher than those for the corresponding GE coal-fired cases, inspite of the fact that the fuel energy savings (fig. 5.5-3) are generally higher for the GE cases.

5.5.2.3 Capital Cost

A capital cost comparison between the contractors' Stirling cogeneration systems is shown in figure 5.5-5. Capital costs in dollars per kilowatt of electricity produced by the system are shown for a 10-MW-electric system with recovery of heat as steam at 300° F. The coal-fired systems are shown in figure 5.5-5(a) and the residual-fueled systems, in part (b). Each contractor estimated the costs according to the cost accounts described in secion 4.1. The bar graphs include all costs of equipment and installation for a 10-MW system, including all fuel-handling, storage, and processing equipment and all heat recovery equipment. Since the engine efficiency is compromised by the recovery of 300° F steam (particularly in the GE configuration), the capital cost in terms of dollars per kilowatt electric is higher than it would be for a noncogenerating engine. Because each cogeneration system produces a different power-to-heat ratio and thus would need a different size and cost supplementary boiler when matched to a common process, bar graphs are also provided that include a supplementary boiler large enough to yield a power-to-heat ratio of 0.25. As indicated in figure 3.2-2, this power-to-heat ratio is near the mean value for all of the processes studied in CTAS.

In figure 5.5-5(a) there are substantial cost differences in each of the cost categories between the GE and UTC systems. However, a comparison of the sums of the first three cost categories (i.e., fuel and waste handling, system heat source, and the power system) indicates costs to be in close agreement ($830/kW electric for UTC; $900/kW electric for GE). Differences in these three individual cost categories may be due to differences in the way the contractors distribute the costs. There is a large difference in the costs for the supplementary boiler (category 5). For the UTC system the supplementary heat demands are met by increasing the size of the AFB. Thus the cost shown in the bar graph is the incremental increase due to the increase in furnace size. GE uses a separate, coal-fired unit with conventional flue gas desulfurization. The UTC system, however, has a much larger supplementary heat load (37 MW thermal) than the GE system (23 MW thermal) because of its much higher power-to-heat ratio. The resulting costs on a dollars-per-kilowatt-thermal basis are substantially different ($12/kW thermal for UTC, $255/kW thermal for GE). For UTC the costs represented by category 6 are those associated with heat rejection equipment for the Stirling engine. This heat is used to heat water for process use, but because this particular case does not require hot water, the heat must be rejected by cooling towers. As shown, this cost is a very small percentage of the total cogeneration cost. The costs for category 7 (balance of plant) are also quite different for the two contractors. Differences in category 8 (contingency and architect and engineering (A&E) services) are due to two factors. First, since these adders are a certain percentage of the total accumulative costs of the other cost categories, the category 8 costs will reflect differences in these accumulated costs. Second, as mentioned in section 4.2, different percentages were used by the contractors for contingency and A&E services. The comparison of the capital costs without the costs for the supplementary boiler indicates a substantial difference in capital cost ($870/kW electric for UTC; $1410/kW electric for GE).

The capital costs for the Stirling cogeneration systems burning residual fuel are shown in figure 5.5-5(b). The total capital cost differences between the contractors are not as great as shown for the coal cases ($825/kW electric for UTC; $1100/kW electric for GE). The total costs for the first three categories are slightly higher for UTC ($510/kW electric for UTC; $440/kW elec-

tric for GE). Large differences in the supplementary boiler (category 5) and balance-of-plant (category 7) cost categories result in the higher GE costs. Both contractors use separately fired residual oil furnaces to satisfy supplementary heat requirements. The UTC supplementary heat requirement is much higher than that of GE, yet because of a low specific cost for its supplementary boiler ($11/kW thermal for UTC; $90/kW thermal for GE), the UTC category 5 cost is much lower. The closest agreement of total capital costs shown in figure 5.5-5 is between the capital costs without a supplementary boiler when burning residual fuel ($740/kW electric for UTC; $825/kW electric for GE).

5.5.2.4 Economics

The levelized annual operating cost saving versus incremental capital cost is shown in figures 5.5-6 and 5.5-7 for both contractors' Stirling systems matched with the nine representative industrial processes. Levelized annual operating cost saving is defined as the difference in levelized annual operating costs for fuel, electricity, and O&M costs between the cogeneration system and the noncogeneration case. In each figure the origin corresponds to the noncogeneration situation, where required power is purchased and onsite steam is produced in a residual-fueled boiler. Since the power requirement varies considerably from process to process (table 4.4-1), the incremental capital cost and levelized operating cost saving are expressed per unit of site power required. As noted, not all of the cogeneration cases are sized to match the site power requirement. Also shown are lines of constant return on investment (ROI). GE's coal-fired cases in figure 5.5-6 generally reach a higher range of operating cost saving than the UTC cases, but because of the higher incremental capital cost the range of ROI is not as high as in the UTC results. The incremental capital costs for the export cases are larger than the costs for the corresponding match-power cases since the onsite energy conversion system is larger. The operating savings of these cases are not raised sufficiently in comparison with the capital cost increase so that the ROI's are lower for export cases than for corresponding match-power cases. The results shown for the residual-fueled cases in figure 5.5-7 indicate lower incremental capital costs and lower operating cost savings. The annual operating cost savings are lower than those for the coal-fired cases because of the higher price of the fuel used in the engine. This results in generally lower ROI's for the residual-fueled cases.

The other economic parameter used in CTAS to combine the effects of capital and operating cost is the percent savings in levelized annual energy cost, defined in section 2.5. The maximum levelized annual energy cost saving ratios (LAECSR) are shown in figure 5.5-8 for the cogeneration Stirling systems matched to the nine representative industrial processes. Only cases that do not involve export are included in figure 5.5-8(a); all cases are included in part (b). When there is more than one matching strategy to choose from, the one with highest LAECSR is shown. In spite of their higher capital costs the coal-fired systems have significantly higher LAECSR's than the coal-derived-liquid-fueled systems because of the lower price of coal. None of the distillate-fueled systems gave an energy cost saving because of the higher price of the distillate fuel.

LAECSR's for cases including export of electricity are shown in figure 5.5-8(b). With only two exceptions the results are the same as those in

figure 5.5-8(a) for both contractors. The cases including export have lower LAECSR's than those without. By including export, excess electricity is generated and sold to a utility at 60 percent of the buying price to the industrial user. However, the increased capital cost component of the levelized annual operating cost and the increased cost of fuel more than offset revenue from the sale of electricity. To look economically attractive, the export cases require a higher sell-back price of electricity.

Comparing the LAECSR's for some of the coal-fired cases in figure 5.5-8 with the fuel energy saving results in figure 5.5-3 shows that some cases with relatively low fuel energy savings have relatively high LAEC savings. This occurs for several processes with low power-to-heat ratio that use a match-power strategy such that a large supplementary boiler is needed in the cogeneration case. Because only a part of the process steam used on site is generated from system waste heat, the fuel energy saving is low. But these results assume the use of residual fuel in the noncogeneration boiler, and both contractors selected coal to generate supplementary steam when coal is used in the cogeneration system. In these cases the operating cost saving is derived from the switch to less expensive fuel rather than from a saving of energy. Since the operating cost is generally the largest contributor to the LAEC, the effect in terms of LAEC is the same. When the same fuel is assumed to be used in cogeneration and noncogeneration cases, this effect does not occur, but the relationship between LAEC savings and fuel energy savings is still complicated by the effects of power-to-heat ratio, matching strategy used, and hours of operation per year. For example, GE's results for coal-fired Stirling engine systems in the meat packing and malt beverage industries show relatively attractive fuel energy savings, but low or zero LAEC savings. The reason is that the hours per year of plant operations are lower than for the other processes, so that the capital cost contribution to LAEC becomes more dominant. These effects and relationships between the parameters used in CTAS are discussed further in terms of some parametric cases in appendix D.

The results in figures 5.5-6 and 5.5-7 generally agree with those in figure 5.5-8, concerning which processes yield the most attractive results for each type of Stirling system. Both indicate that the exclusion of export of electricity and the use of coal as a fuel for the Stirling system yield more attractive results economically.

5.5.2.5 Relative National-Basis Fuel Saving

Fuel savings accumulated to a national basis are shown in figures 5.5-9 to 5.5-11 as a function of hurdle return on investment (ROI). The procedure used to calculate these curves is described in section 4.4. It was assumed for each system that it would be 100 percent implemented in new-capacity additions or retirement replacements between 1985 and 1990 in each process for which the results yield an ROI greater than the hurdle rate shown. Results were calculated for the GE systems using 40 of the processes and for the UTC systems using 26 processes. No extrapolation beyond these processes was done. These figures are intended to illustrate the comparative potential saving versus ROI requirements, not the absolute magnitude of savings.

The potential national energy savings are shown for the coal-fired Stirling engine in figure 5.5-9. Only cogeneration strategies that do not involve export of power from an individual plant site are included. Note that

the UTC results extend to a higher range of ROI than the GE results. The UTC results show some processes that achieve a higher ROI than shown in figure 5.5-6 for the subset of nine processes. For the GE cases the potential national fuel saving if an ROI greater than 10 percent is required is about half that if no hurdle ROI is applied. For the UTC cases 75 percent of the total potential fuel saving is achieved by processes with ROI's greater than 10 percent. The results for the coal-fired systems when export of power from individual plant sites is allowed are shown in figure 5.5-10. In both parts of the figure the potential national fuel savings shown for low ROI hurdle rates are higher than the savings shown in figure 5.5-9, which does not include export. Using a cogeneration strategy that involves export increases the plant-site fuel energy saving in some cases, as shown in figure 5.5-3, but generally results in lower ROI. Therefore the processes appearing in figure 5.5-10 are generally at lower ROI than those in figure 5.5-9. As a result, at higher hurdle ROI rates the accumulative national fuel energy savings in figure 5.5-10 are lower than those shown in figure 5.5-9.

The potential national fuel savings for the residual-fueled Stirling engines are shown in figure 5.5-11, assuming that no power export is considered. Because of the higher price of fuel the ROI's were generally lower for the residual-fueled Stirling engines than for the coal-fired versions, as indicated in figures 5.5-6 and 5.5-7. As a result, at the higher hurdle ROI rates, fewer processes are shown and the accumulative national fuel energy savings are lower in figure 5.5-11 than those shown in figure 5.5-9 for the coal-fired cases.

5.5.3 Summary

The range of results achieved by the Stirling systems for the nine representative industrial processes is shown in table 5.5-3. For each parameter the industrial process that yields the maximum value is also indicated. Generally, the fuel energy saving ratio (FESR) is good for both contractor studies, with maximum values in the mid to upper 20's without export and in the mid to upper 30's with export. The GE system without export results in highest FESR when matched to the newsprint process. The GE newsprint process requires a power-to-heat ratio that closely matches the ratio produced by the GE Stirling engine system at the required steam temperature (366° F). For UTC the Stirling engine system match with meat packing results in the highest FESR for the coal-fired system and among the highest for the residual-fueled system. Meat packing requires some of its process heat in the form of hot water. The system configuration studied by UTC results in very little heat being recovered from engine heat rejection if hot water is not needed by the process. (Process steam is generated from heat taken from the intermediate heat transfer loop, which transfers heat from its furnace to the engine.) Thus the fuel energy savings achieved by UTC systems tend to be higher for processes that require hot water. For the residual-fueled Stirling engine system studied by UTC the steel process provides a better power-to-heat-ratio match and hence slightly higher FESR than the meat packing process. When export of electricity is allowed, the highest FESR for both the residual-fueled and coal-fired Stirling cases is with malt beverages for GE and meat packing for UTC. Both of these industrial processes require a considerable amount of hot water, and as shown in figure 5.5-2(a) the Stirling cogeneration performance improves appreciably when all of the engine waste heat can be recovered in the form of hot water.

This can be accomplished for these processes in a matching strategy that allows power export.

The emissions saving ratios are higher for the liquid-fueled systems than for the coal-fired systems mainly because of the lower rate of SO_2 emissions from the liquid-fueled systems. The UTC coal-fired systems show higher EMSR than the GE coal-fired systems mainly because UTC assumed a lower rate of NO_x emissions from the fluidized-bed furnace than GE assumed for the pulverized-coal-fired furnace. As would be expected, the industries in which the highest EMSR values are achieved generally are those in which the highest fuel savings are achieved.

The levelized annual energy cost saving is dominated by the operating cost saving, so the values achieved are higher for the coal-fired systems because of the lower price of that fuel. There is no increase in LAEC when including export of electricity, since the higher capital cost of the system when exporting electricity more than offsets the revenue from the sale of the excess power. A higher sell-back price for the excess power (60 percent of the utility selling price was assumed) would significantly improve the export cases.

For the results shown, the noncogeneration onsite boiler was selected to use a residual-grade fuel. Both contractors assumed that any supplementary boiler required in coal-fired cogeneration systems would be also coal fired. Thus, in low-power-to-heat-ratio processes the LAEC saving is higher not only because of a saving in fuel energy due to cogeneration, but also because of a switch to coal rather than the more expensive coal-derived residual fuel in the onsite boiler. This is the reason for high LAEC savings in the petroleum process in both contractors' results. The Stirling engine system has better cogeneration performance when hot water is required by the process. However, the contractors' industrial data indicate relatively few industries where substantial amounts of hot water are required. This hurt the prospects for the UTC Stirling engine system, which has a configuration such that a substantial amount of heat from the Stirling engine is wasted when hot water is not required. In some of the processes that do need hot water (such as the food industry), the hours of operation per year are low. The operating cost savings per year are therefore lower than for processes operating at higher load factors, and thus the economic results are not attractive.

TABLE 5.5-1. - ENERGY CONVERSION SYSTEM PARAMETERS STUDIED FOR STIRLING ENGINE SYSTEMS

Parameter	General Electric Co.	United Technologies Corp.
Coal-fired systems		
Approach	Flue gas desulfurization	Atmospheric fluidized bed
Maximum working-gas temperature, °F	1390	1450
Minimum working-gas temperature °F	Varies with process temperature	150
Heat transfer method	Integrated gas loop	Integrated gas loop
Source of process heat	Engine coolant and combustion gas economizer	Engine coolant and integrated gas loop
Working fluid	Helium	Helium
Maximum module size, MW electric	2	30
Liquid-fueled systems		
Fuel	Distillate, residual	Residual
Maximum working-gas temperature, °F	1390	1600
Minimum working-gas temperature, °F	Varies with process temperature	150
Heat transfer method	Tubes in combustion zone	Integrated gas loop
Source of process heat	Engine coolant and combustion gas economizer	Integrated gas loop
Working fluid	Helium	Helium
Maximum module size, MW electric	2	30

TABLE 5.5-2. - EMISSIONS FOR STIRLING ENGINE SYSTEMS

Pollutant	Fuel				
	Coal		Coal-derived residual		Coal-derived distillate (GE)
	GE FGD[a]	UTC AFB	GE	UTC	
	Emissions, $lb/10^6$ Btu				
Oxides of sulfur	1.2	1.2	0.8	0.824	0.56
Oxides of nitrogen	.7	.2	.7	.500	.46
Particulates	.1	.1	.153	.100	.034

[a]Pulverized coal.

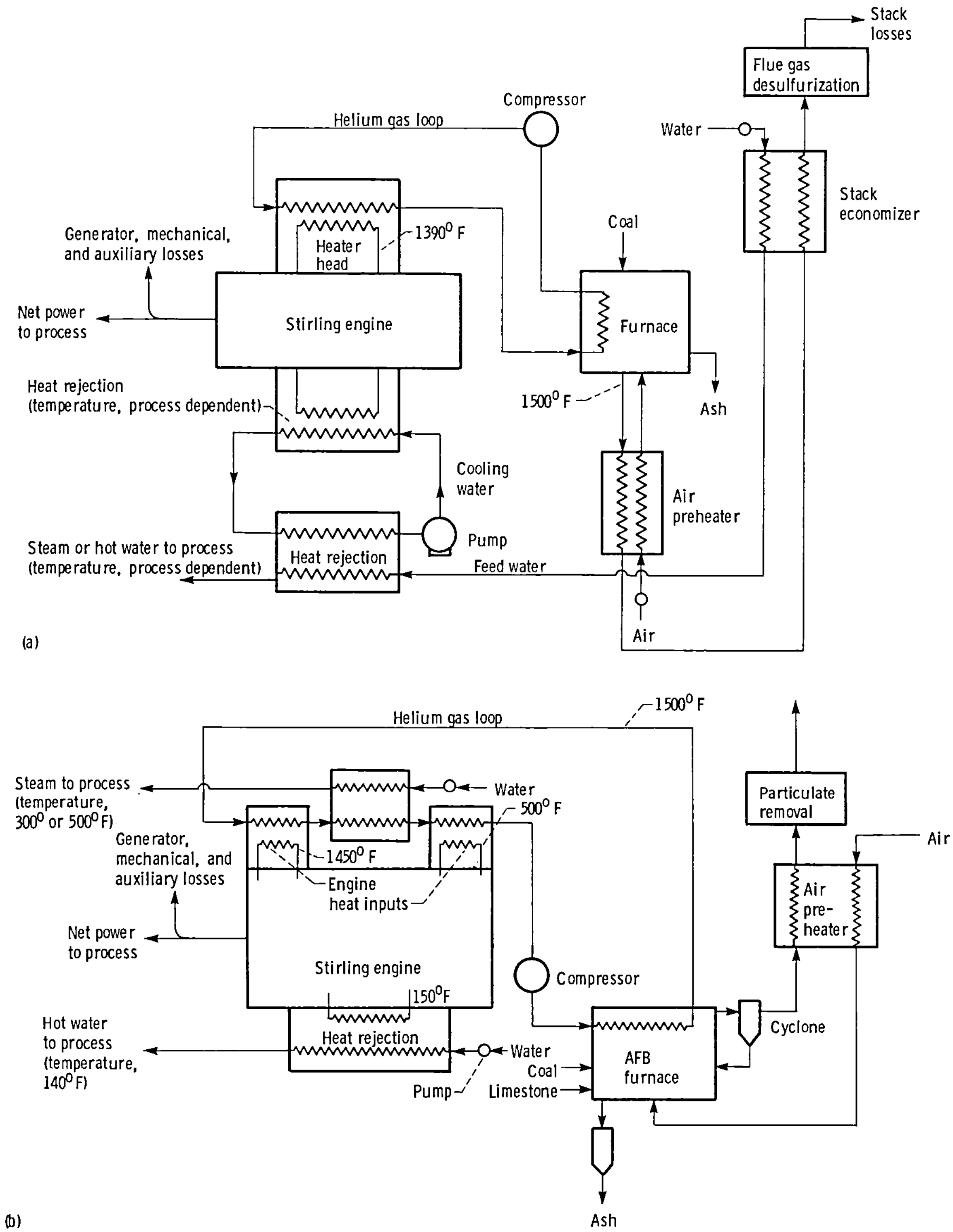
TABLE 5.5-3. - RANGE OF RESULTS FOR STIRLING ENGINE SYSTEMS USED WITH NINE REPRESENTATIVE INDUSTRIES

(a) No power export allowed

Energy conversion system subgroup	Contractor	Fuel energy saving ratio, FESR	Industry with maximum FESR	Emissions saving ratio, EMSR	Industry with maximum EMSR	Levelized annual energy cost, LAEC	Industry with maximum LAEC	Return on investment ROI percent	Industry with maximum ROI
Stirling engine/liquid	GE(distillate)	8.1-24.4	Newsprint	19-57	Newsprint	Negative to 0	Nylon	0-5	Nylon
	GE(distillate)	8.1-24.4	Newsprint	8-26	Newsprint	Negative to 7.8	Writing paper	0-19	Nylon
	UTC	1.8-29.0	Steel	5.3-49.4	Steel	Negative to 2.6	Writing paper	0-7	Writing paper
Stirling engine/coal	GE(distillate)	9.0-24.4	Newsprint	Negative to 18	Newsprint	Negative to 25.4	Petroleum	0-18	Petroleum residual
	UTC	3.2-23.2	Meat packing	12.4-39.6	Steel	9.9-30.1	Petroleum	7-22	Petroleum residual

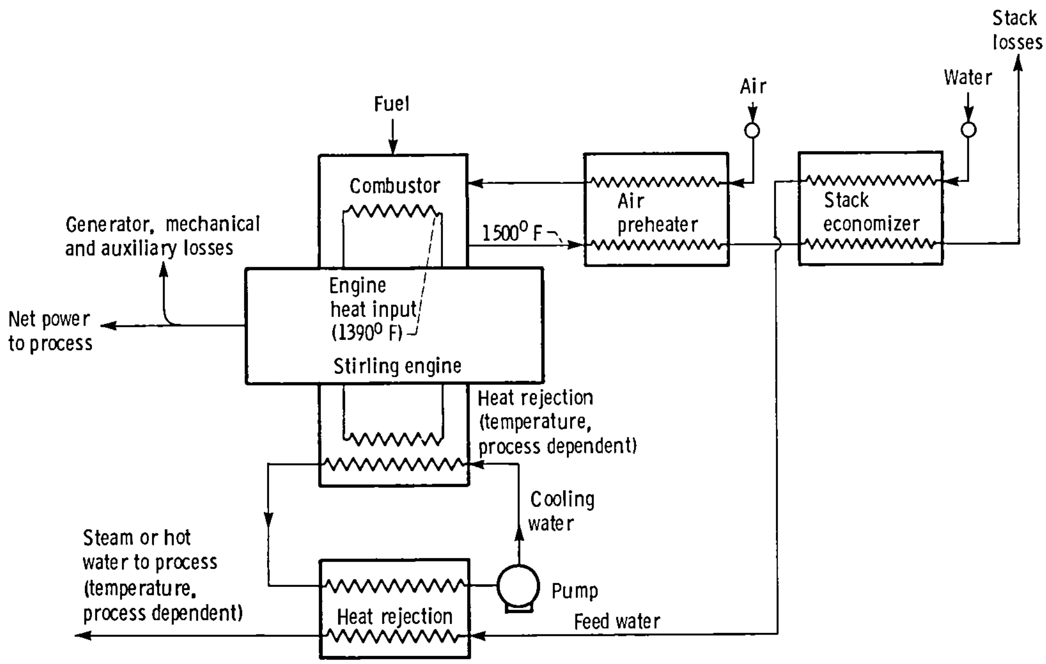
(b) Power export allowed

Energy conversion system subgroup	Contractor	Fuel energy saving ratio, FESR	Industry with maximum FESR	Emissions saving ratio, EMSR	Industry with maximum EMSR	Levelized annual energy cost, LAEC	Industry with maximum LAEC	Return on investment ROI percent	Industry with maximum ROI
Stirling engine/liquid	GE(distillate)	8.1-34.1	Malt beverage	19-62	Malt beverage	Negative to 0	Nylon	0-5	Nylon
	GE(distillate)	8.1-34.1	Malt beverage	8-35	Malt beverage	Negative to 7.8	Writing paper	0-19	Nylon
	UTC	1.8-37.7	Meat packing	4.7-53.9	Meat	Negative to 4.0	Chlorine	0-7	Writing paper
Stirling engine/coal	GE(distillate)	9.0-34.1	Malt beverage	Negative to 28	Malt beverage	Negative to 25.4	Petroleum	0-18	Petroleum residual
	UTC	3.2-32.1	Meat packing	12.4-46.7	Meat packing	3.1-30.1	Petroleum	6-22	Petroleum residual

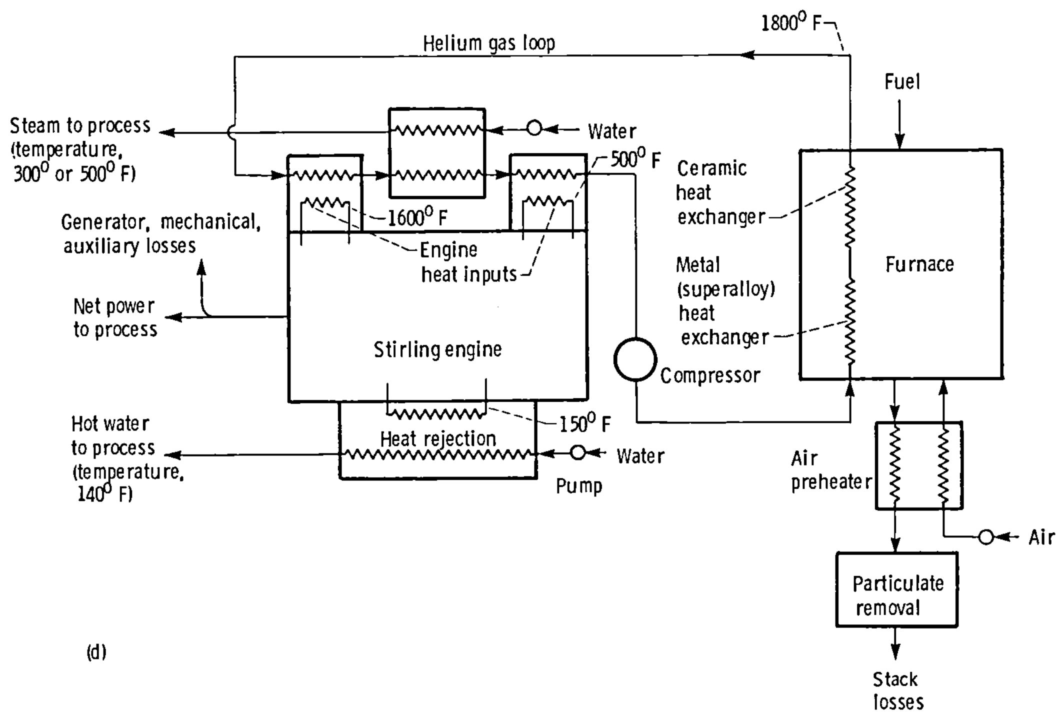


(a) GE coal fired.
(b) UTC coal fired.

Figure 5.5-1. - Schematics of Stirling engine systems.



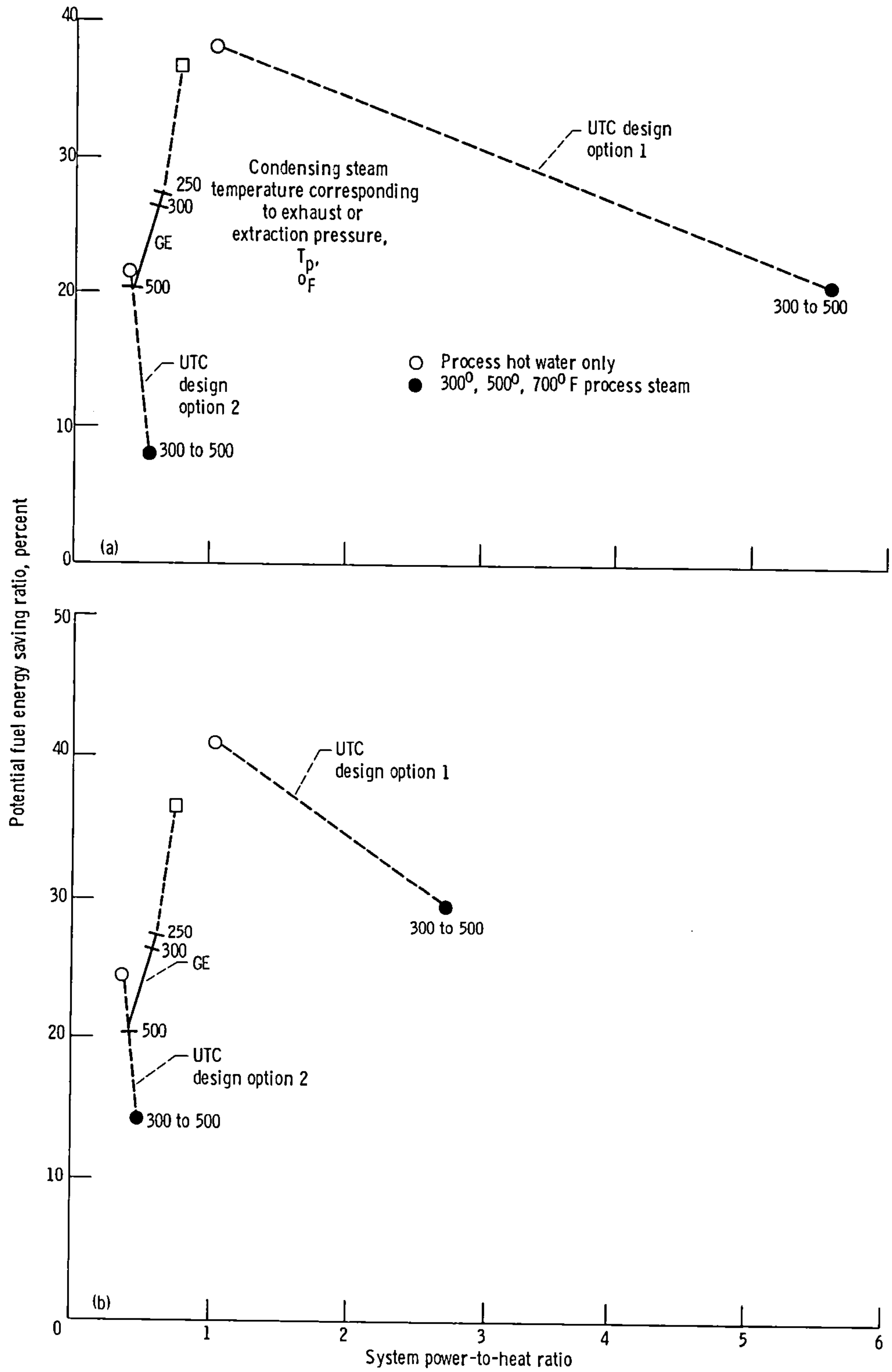
(c)



(d)

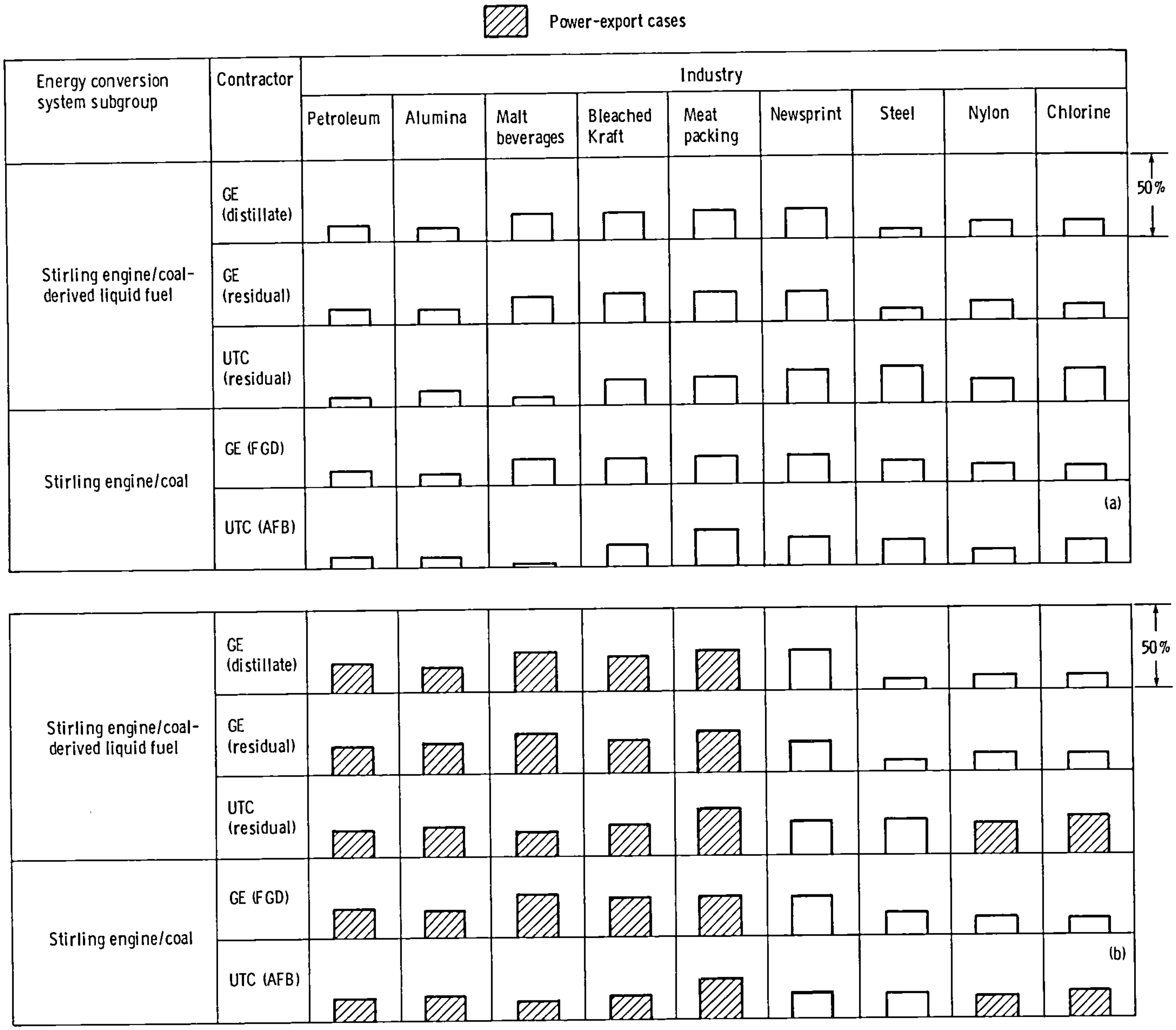
(c) GE liquid fueled.
(d) UTC residual fueled.

Figure 5.5-1. - Concluded.



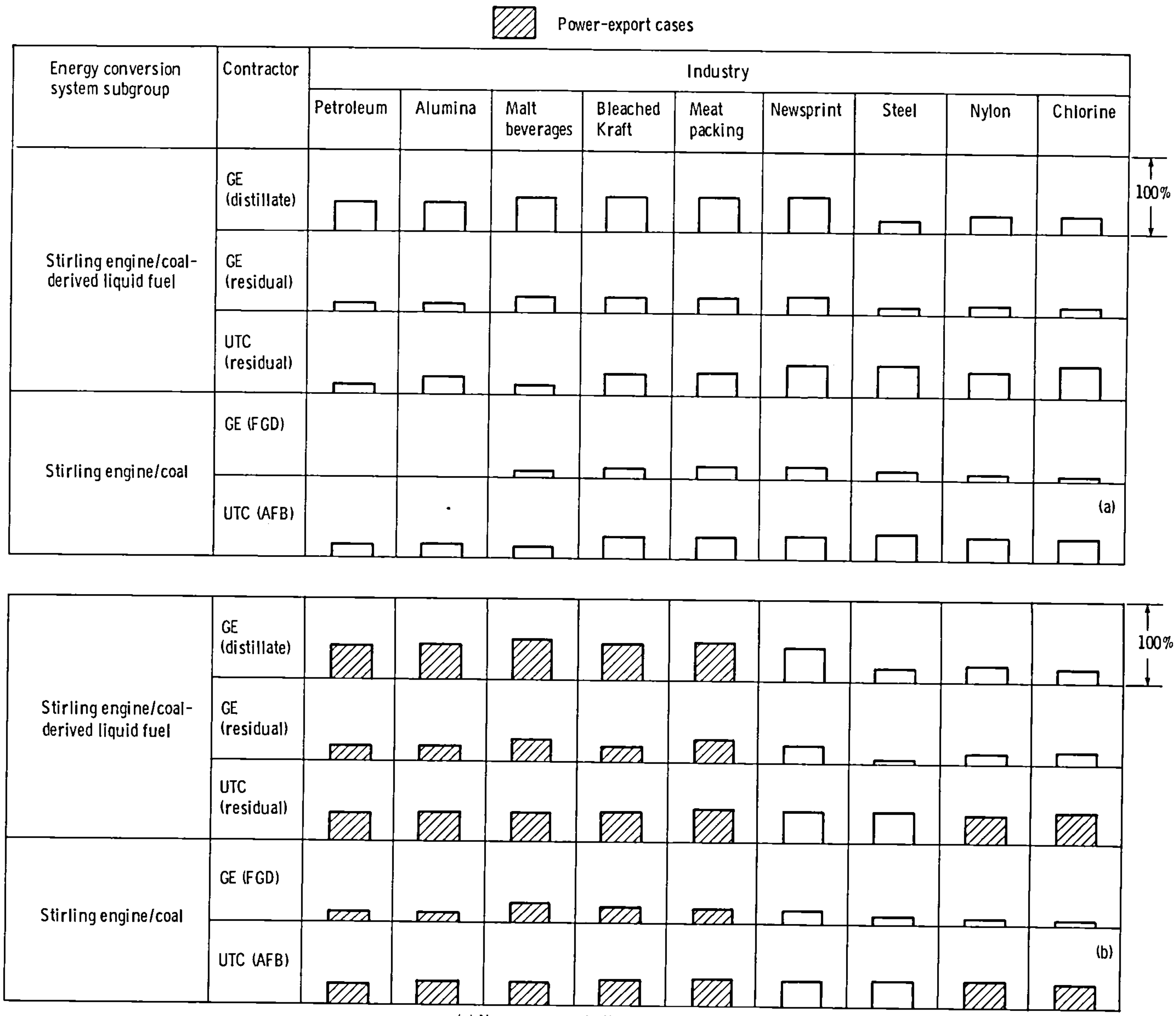
(a) Coal-fired system.
(b) Residual-fueled system.

Figure 5.5-2. - Potential fuel energy saving ratios for Stirling engine systems.



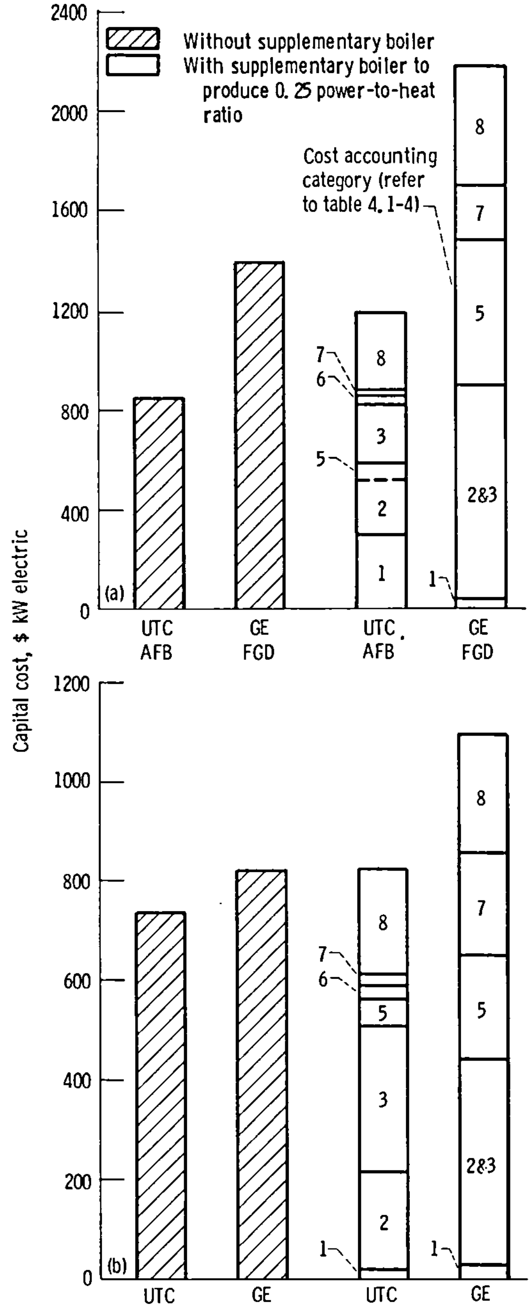
(a) No power export allowed.
(b) Power export allowed.

Figure 5.5-3. - Fuel energy saving ratios for Stirling engine systems.



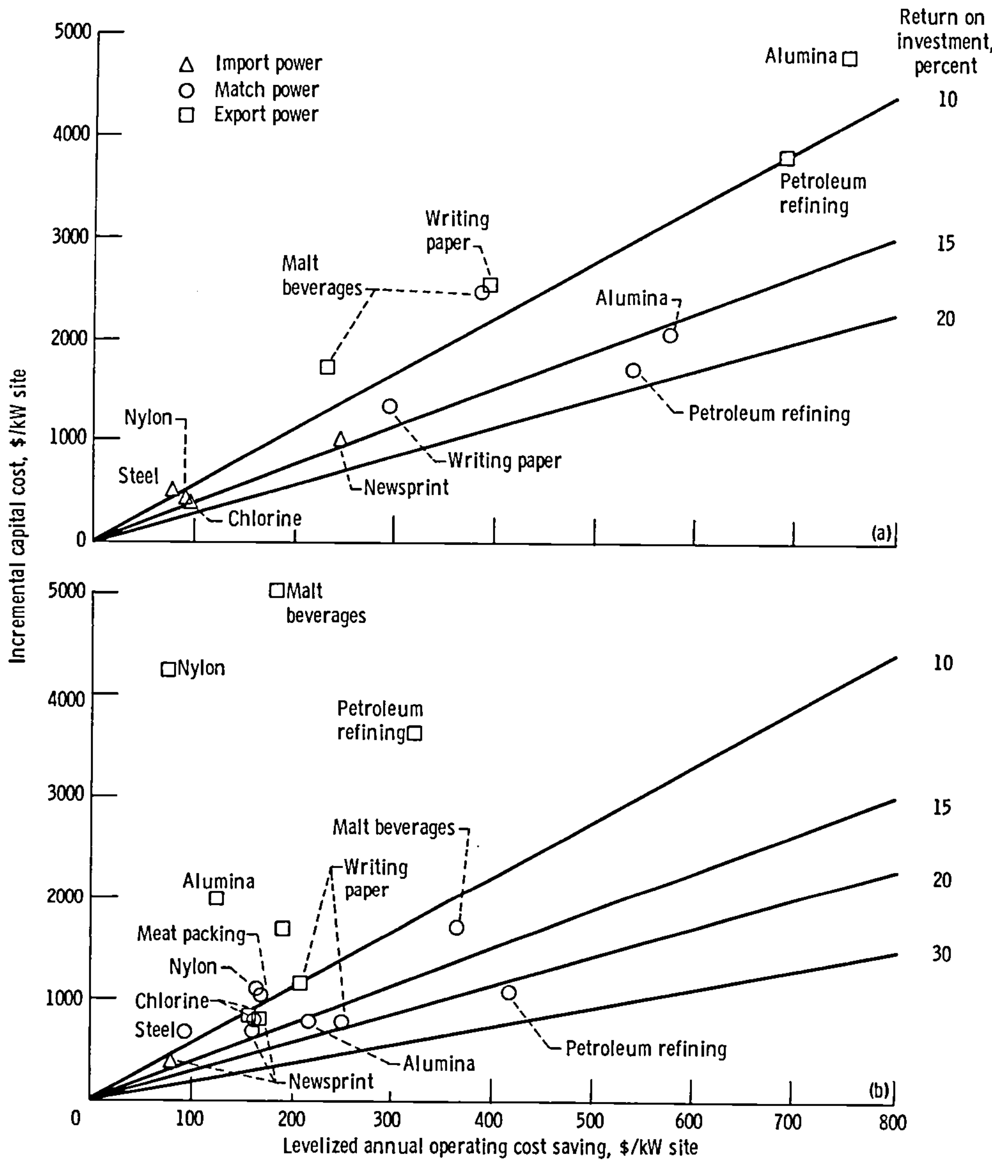
(a) No power export allowed.
(b) Power export allowed.

Figure 5.5-4. - Emissions saving ratios for Stirling engine systems. (Blanks denote all negative values.)



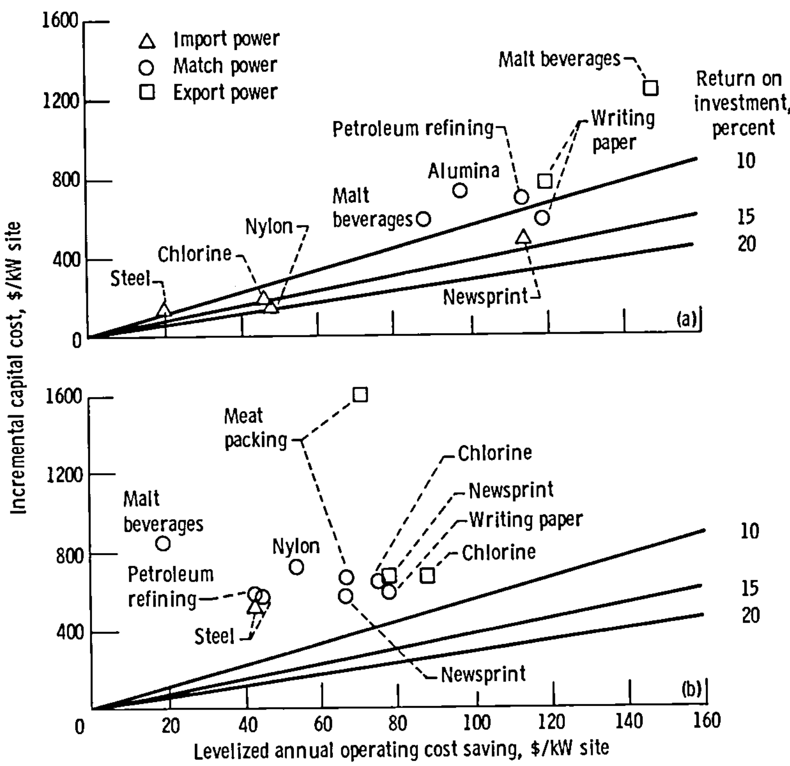
(a) Coal-fired systems.
(b) Residual-fueled systems.

Figure 5.5-5. - Capital costs for Stirling engine systems. Electricity generated, 10 MW; process steam temperature, 300° F.



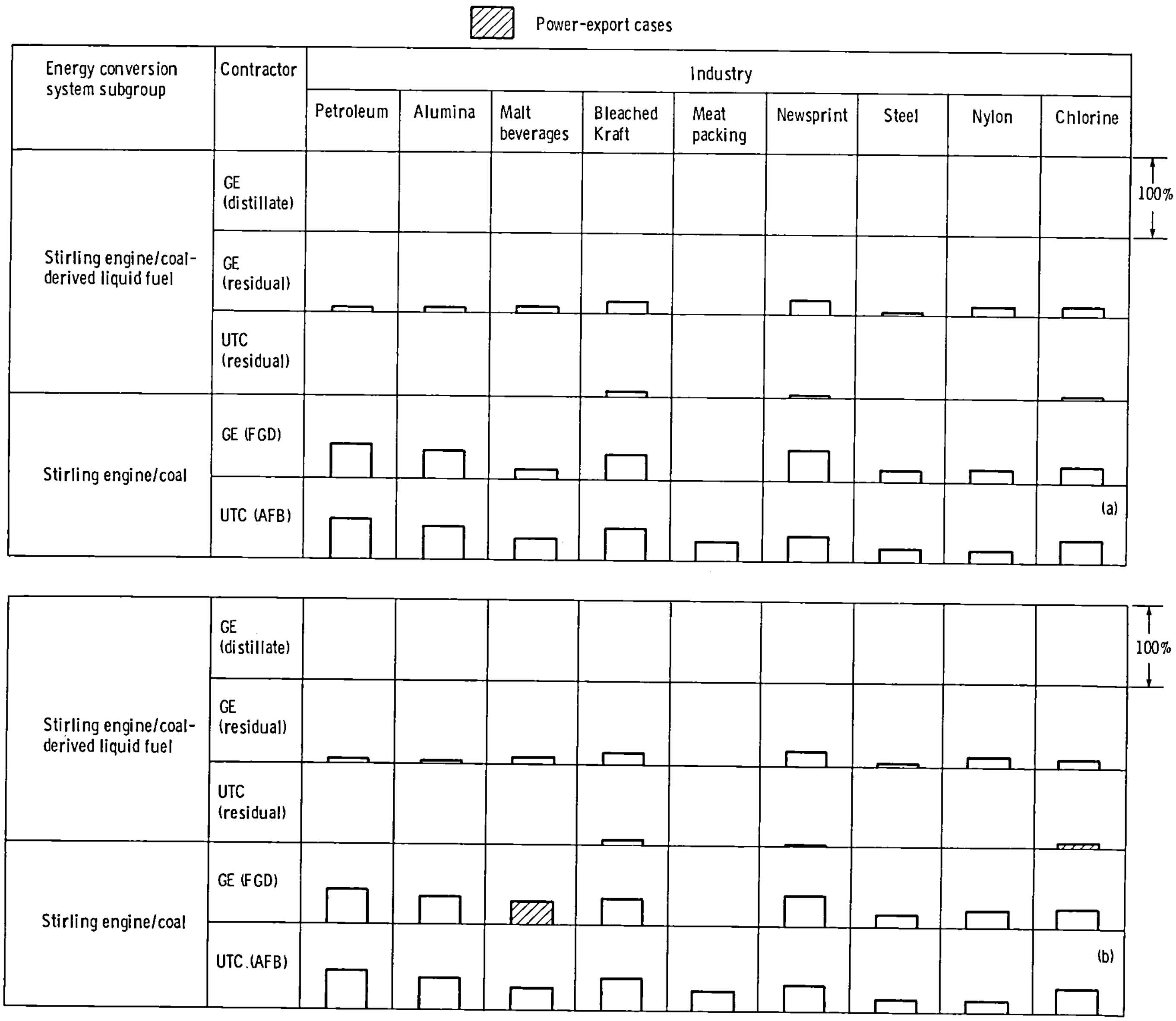
(a) GE.
(b) UTC.

Figure 5.5-6. - Incremental capital cost as a function of levelized annual operating cost saving for coal-fired Stirling engine systems.



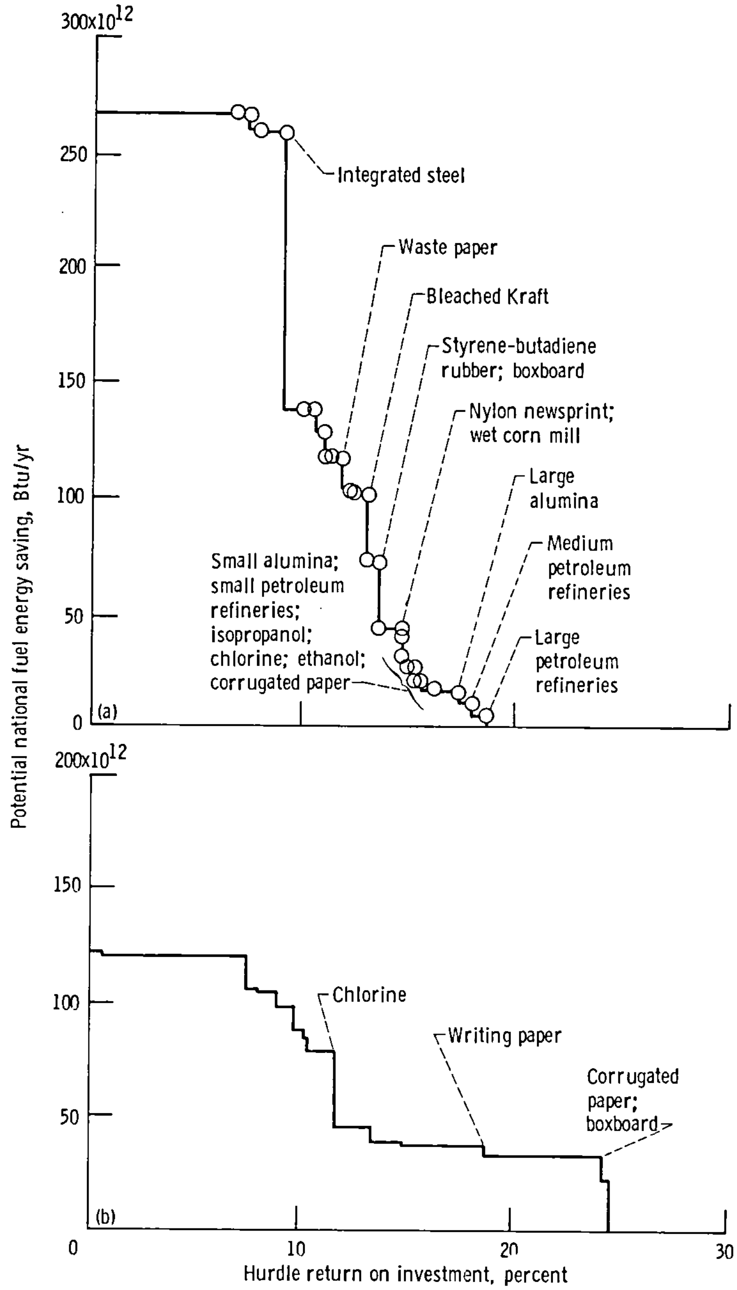
(a) GE.
(b) UTC.

Figure 5.5-7. - Incremental capital cost as a function of levelized annual operating cost saving for residual-fueled Stirling engine systems.



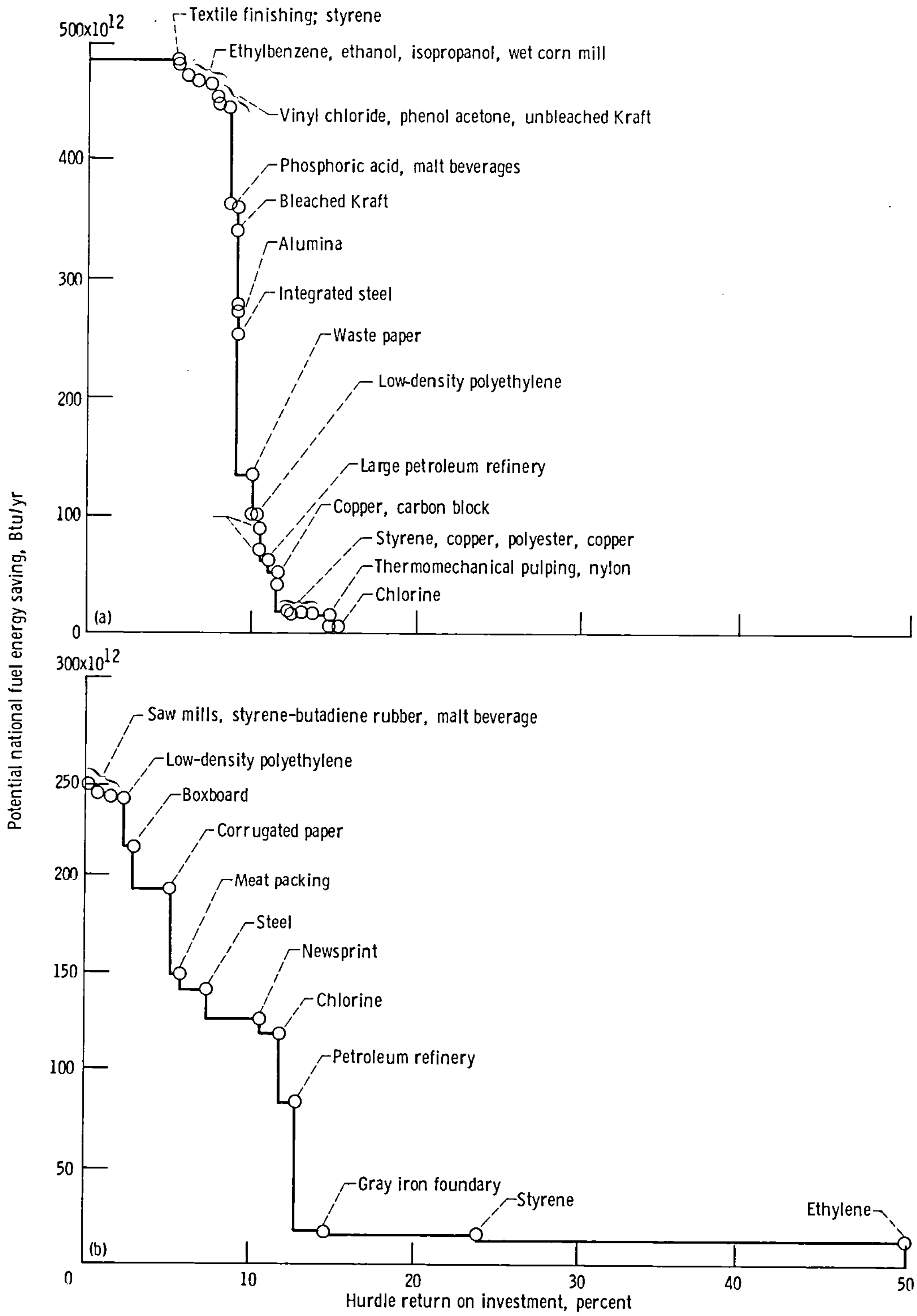
(a) No power export allowed.
(b) Power export allowed.

Figure 5.5-8. - Levelized annual energy cost saving ratios for Stirling engine systems. (Blanks denote all negative values.)



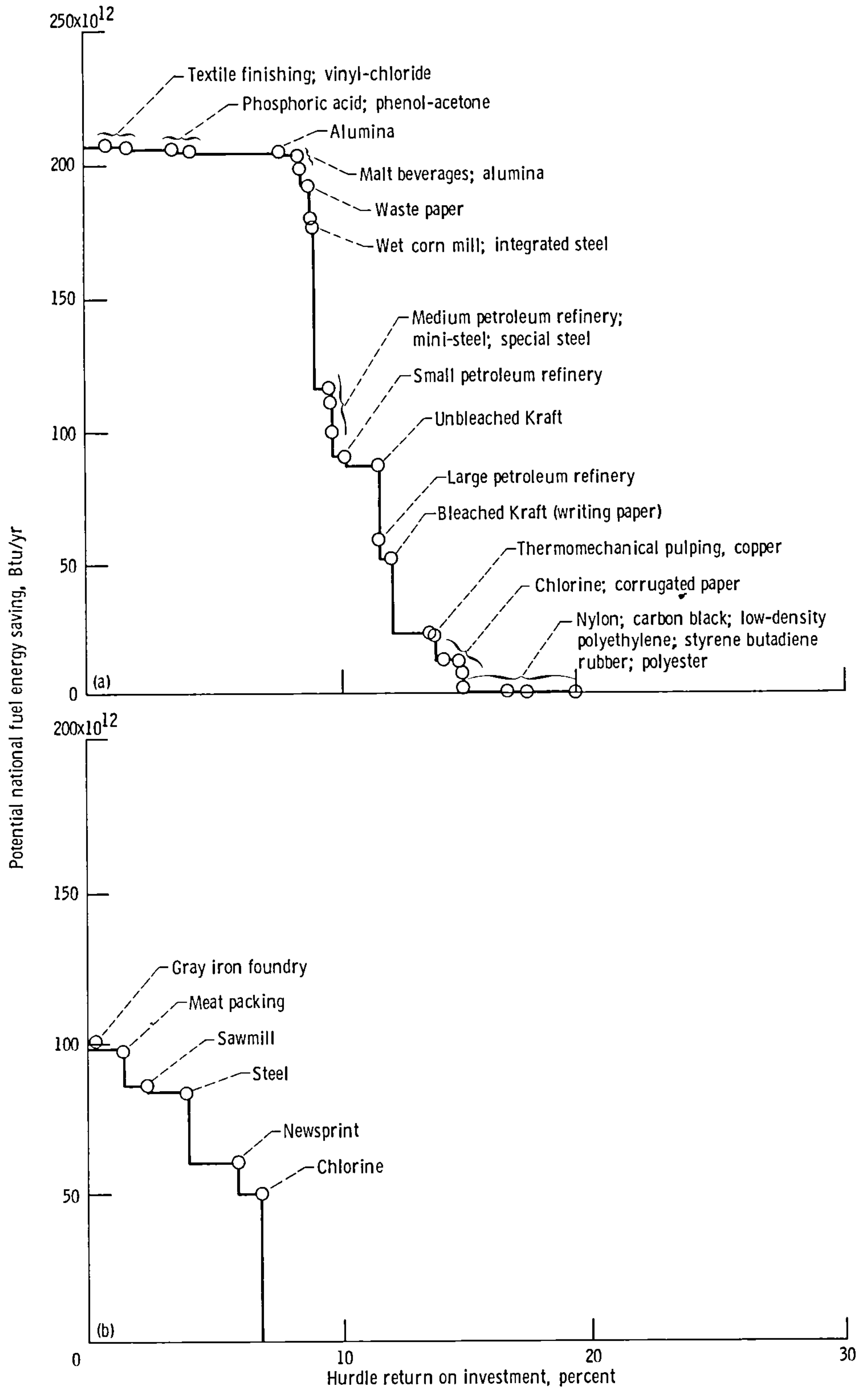
(a) GE.
(b) UTC.

Figure 5.5-9. - Potential national fuel energy saving as a function of hurdle return on investment for coal-fired Stirling engine systems. (No power export allowed.)



(a) GE.
(b) UTC.

Figure 5.5-10. - Potential national fuel energy saving as a function of hurdle return on investment for coal-fired Stirling engine systems. (Power export allowed.)



(a) GE.
(b) UTC.

Figure 5.5-11. - Potential national fuel energy saving as a function of hurdle return on investment for residual-fueled Stirling engine systems. (No power export allowed.)

5.6 CLOSED-CYCLE GAS TURBINE SYSTEMS

Joseph J. Nainiger

5.6.1 Configurations and Parameters

The parameters considered for each contractor are shown in table 5.6-1. Schematics for the simple and recuperated closed-cycle configurations are shown in figure 5.6-1. Both contractors considered coal-fired, atmospheric-fluidized-bed configurations with in-bed desulfurization by means of a limestone sorbent at a turbine inlet temperature of 1500° F with simple and recuperated cycles. General Electric assumed only helium as the working fluid; United Technologies investigated the use of either helium or air as the working fluid for the coal-fired cases. UTC also considered the use of a coal-derived liquid fuel with the closed-cycle gas turbine. For these cases the turbine inlet temperature is 2200° F with either helium or air as the working fluid. The high turbine inlet temperature is attained by using a ceramic heat exchanger within the furnace. Both simple- and recuperated-cycle configurations were investigated for the liquid-fueled cases.

GE and UTC used different compressor inlet temperatures, with GE assuming 80° F and UTC assuming 190° or 300° F. The choice of compressor inlet temperature affects the cogeneration performance of the closed-cycle gas turbine when matched to an industrial process. The lower compressor inlet temperature results in a higher electrical efficiency but in a lower fraction of the available rejected heat from the cycle being recovered for process use. In contrast, the higher compressor inlet temperature results in lower electrical efficiency but in a higher fraction of the available heat from the turbine being recovered. The energy conversion system power-to-heat ratio is higher in the former case and lower in the latter. The effect on cogeneration performance is explained further in the next section.

5.6.2 Cogeneration System Performance

5.6.2.1 Fuel Energy Saving Ratio

The ratio of power to process heat produced for a range of process steam (or hot water) conditions is shown in figure 5.6-2, together with the cogeneration fuel energy saving that would be achieved if the power-to-heat ratio matches the process needs. As discussed in appendix D, if the site-required power-to-heat ratio differs from the value provided by the system, as shown in this figure, the fuel saving in most cases will be lower. Only if the process requires a power-to-heat ratio lower than that produced by the system, and a match-heat - export-power strategy is used, will the fuel energy saving ratio (FESR) equal the value shown in this figure. Points designated as "hot water only" represent cogeneration performance if the process requirement is assumed to be only hot water. The coal-fired systems are shown in figure 5.6-2(a) and the residual-fueled systems, in part (b).

The results for the closed-cycle gas turbine burning coal in an atmospheric fluidized bed are shown in figure 5.6-2(a). Five design options are shown for UTC. These design options are described in table 5.6-2(a). Design options 1 and 2 represent simple-cycle configurations with air as the working fluid and a compressor pressure ratio of 6. In design option 1 the compressor inlet temperature is 190° F; in design option 2 it is 300° F. As mentioned

previously, design option 2 has a lower power-to-heat ratio than design option 1 because of its lower electrical efficiency and higher heat recovery factor. When just the raising of process steam is considered, design option 2 has a higher potential fuel energy saving than design option 1, in spite of its lower electrical efficiency. This higher performance is a result of a higher fraction of waste heat being recovered for process use. The relationship of electrical efficiency and heat recovery with fuel energy saving is described in more detail in appendix D.

Design option 3 represents a recuperated configuration (effectiveness, 0.85) with air as the working fluid, a compressor pressure ratio of 6, and a compressor inlet temperature of 190° F. Because of recuperation the electrical efficiency is higher in design option 3 than in design options 1 and 2, and this results in a higher power-to-heat ratio. Also, recuperation results in lower temperature waste heat for process heat recovery than is available in the simple-cycle configuration, and thus less heat is available to raise high-temperature process steam. Therefore the recuperated case is not capable of raising 700° F process steam, and the cogeneration performance when raising 500° F steam is lower than that for the simple-cycle design options when raising steam at the same condition.

In UTC's design options 4 and 5, helium is used as the working fluid with a compressor inlet temperature of 190° F and a compressor pressure ratio of 3. Design option 4 represents a simple-cycle configuration; and design option 5, a recuperated cycle. As mentioned previously, the simple-cycle configuration has a lower power-to-heat ratio than the recuperated case. These two design options have lower potential fuel energy savings than the design options using air as the working fluid. For this reason, in almost all cases, one of the design options using air was chosen by UTC as a better match with an industrial process. For the low-power-to-heat-ratio processes one of the simple-cycle design options was used (design option 1 or 2); for the high-power-to-heat-ratio processes the recuperated design option (design option 3) was used.

Three closed-cycle gas turbine configurations are shown for GE in figure 5.6-2(a). These correspond to a simple-cycle configuration (recuperator effectiveness, 0), and to two recuperated cases with recuperator effectivenesses of 0.60 and 0.85. As shown, the case with highest recuperator effectiveness (0.85) extends out to a very high power-to-heat ratio with increasing process steam temperature. As mentioned previously the use of recuperation results in lower temperature waste heat being available to raise process steam. Therefore a lower fraction of heat is recovered with increasing process steam temperature. Likewise, GE's use of an 80° F compressor inlet temperature means that, in most cases, a considerable amount of waste heat is rejected to cooling towers to get the low compressor inlet temperature. Although the low compressor inlet temperature results in higher electrical efficiency, the rejection of a large fraction of waste heat to achieve the lower temperature results in lower heat recovery and thus in much higher power-to-heat ratios than for the UTC cases, which have higher compressor inlet temperatures. The use of a lower compressor inlet temperature is desired in a closed-cycle gas turbine when it is used as an electric power generator only. However, as shown for the GE highly recuperated case, the use of low compressor inlet temperatures results in power-to-heat ratios very much higher than required by most processes, and this means low fuel energy savings when the systems are matched to those processes.

The use of a lower recuperator effectiveness (0.60) or the elimination of the recuperator (simple cycle) is shown in figure 5.6-2(a) to result in lower system power-to-heat ratios and lower potential fuel energy savings. The potential fuel energy savings for these two GE cases are lower than those for the UTC cases. This is a result of the use by GE of lower compressor inlet temperatures and helium as the working fluid. The use of helium as the working fluid has an advantage in that helium has better heat transfer characteristics than air, thus requiring less heat transfer area in heat exchangers. The use of helium also means smaller turbomachinery. A disadvantage of using helium is that it results in lower turbomachinery efficiencies and thus in lower overall performance.

The potential fuel energy savings and system power-to-heat ratios are shown in figure 5.6-2(b) for closed-cycle gas turbines burning coal-derived residual fuel as studied by UTC. Five design options are shown. These design options are described in table 5.6-2(b). The compressor inlet temperature is assumed to be 190° F. The first three design options assume air as the working fluid. Design option 1 represents a recuperated cycle (recuperator effectiveness, 0.85) with a compressor pressure ratio of 6. Design options 2 and 3 represent simple-cycle configurations (recuperator effectiveness, 0) with compressor pressure ratios of 6 and 14, respectively. The recuperated case has the highest power-to-heat ratio with the two simple-cycle configurations having lower power-to-heat ratios. Design options 4 and 5 represent cases where helium is used as the working fluid. Design option 4 is a recuperated case (recuperator effectiveness, 0.85) with a compressor pressure ratio of 4, design option 5 is a simple-cycle configuration with a compressor pressure ratio of 6. As with the coal-fired cases the design options using helium have lower potential fuel energy savings than those using air. For this reason the cases using air are most often matched with the industrial processes.

A comparison of the cases shown in figure 5.6-2(b) with the coal-fired AFB cases shown in part (a) indicates higher potential fuel energy savings for the liquid-fueled systems. This is primarily the result of the higher turbine inlet temperatures for the systems burning coal-derived residual fuel (2200° F). As mentioned previously the high turbine inlet temperature is attained by the use of ceramic heat exchangers within the furnace. The higher turbine inlet temperature results in higher electrical efficiency and also a greater fraction of the waste heat being recovered for a given process steam temperature and thus in higher fuel energy savings. Also, in both figures 5.6-2(a) and (b) a considerable increase in fuel energy saving is shown when only hot water is required by the process. This is due to greater recovery of the system waste heat. Thus the closed-cycle gas turbine is expected to have higher fuel energy saving when matched to a process that requires a considerable amount of heat in the form of hot water.

The fuel energy saving ratio results of closed-cycle gas turbine systems matched to the nine representative industries are shown in figure 5.6-3. The characteristics of these processes are listed in section 4.4. The processes are listed in figure 5.6-3 in ascending order of power-to-heat ratio. Only matching strategies that produce no excess of power are included in part (a). In part (b) all matching strategies are considered, and the matching strategy that yields the highest FESR is shown. When power export is excluded (fig. 5.6-3(a)), the FESR's for the liquid-fueled systems studied by UTC are good for most of the nine processes. The design options chosen by UTC

(fig. 5.6-2(b)) cover a wide range of power-to-heat ratio with very good potential fuel energy savings, making it possible to match well with various processes over a wide range of power-to-heat ratio. For the UTC coal-fired AFB systems large FESR's are indicated for those processes that require part of their process heat in the form of hot water (bleached Kraft (writing paper), meat packing, and newsprint) and for those processes where byproduct fuel is assumed to be burned in the AFB (bleached Kraft (writing paper), newsprint, and steel). For the GE coal-fired AFB systems the highest FESR is attained in the malt beverage and meat packing processes, which require part of their process heat in the form of hot water, and in the nylon and chlorine processes, which have high power-to-heat ratios corresponding to the higher power-to-heat ratios produced by the GE systems (fig. 5.6-2(a)). Note that in most processes the UTC systems attain higher FESR's.

The fuel energy saving results obtained for these nine processes when export of power is allowed are shown in figure 5.6-3(b). The FESR results are improved over those in part (a) in many cases where using a larger power system and making excess power results in a greater amount of heat recovery for process use. The cases that involve export are crosshatched; the others correspond to a match-power or import situation and are the same as in part (a). The lower the site-required power-to-heat ratio as compared with that produced by the system, the greater the amount of excess power produced in a match-heat strategy. This will affect the economic results, as illustrated in later figures and parametrically in appendix D. Since the GE closed-cycle gas turbines produce a higher power-to-heat ratio (fig. 5.6-2(a)), the amount of export power is generally greater in GE cases.

As shown in figure 5.6-3(b), for the GE systems the meat packing and malt beverage processes yield the highest FESR's because of their requirement for hot water. Likewise, for the UTC AFB systems, the highest FESR's are achieved for those processes requiring hot water, using byproduct fuel, or both. For the UTC cases using coal-derived residual fuel, high of FESR's are again indicated for all of the processes, with an increase in FESR because of power export for those processes with lower required power-to-heat ratios.

5.6.2.2 Emissions Saving Ratio

The emissions saving ratios (EMSR) for the closed-cycle gas turbine systems matched to the nine representative industrial processes are shown in figure 5.6-4. The emissions saving ratio, defined in section 2.5, is the percentage reduction in emissions when both the utility site and the industrial site are considered. The results shown in figure 5.6-4 correspond to the total of NO_x, SO_x, and particulate emissions and are calculated by assuming the use of coal-derived residual-fuel in the noncogeneration onsite boiler. For the UTC cases coal was assumed to be used at the utility. For the GE cases a fuel mix consisting of 77 percent coal and 23 percent coal-derived residual fuel was assumed to be used by the utility. In addition to the amount of fuel saved, the emissions saving depends strongly on the combustion characteristics of the energy conversion system and the type of fuel used. The emissions per unit of fuel consumed are shown in table 5.6-3 for each contractor's systems. The emissions saving ratios for the system using coal-derived residual fuel in figure 5.6-4 are highest because of the higher fuel energy savings shown in figure 5.6-3 and the slightly lower emissions rates shown in table 5.6-3. For the coal-fired cases the emissions saving ratios for the UTC cases in figure 5.6-4 are generally higher than those for GE. This is due to the higher fuel

energy savings for the UTC systems as shown in figure 5.6-3, to the lower emissions estimates for the UTC atmospheric fluidized bed (table 5.6-3), and to the use of a higher percentage of coal by the utility for the UTC cases.

5.6.2.3 Capital Cost

A capital cost comparison between the contractors' closed-cycle gas turbine cogeneration systems is shown in figure 5.6-5. Capital costs in dollars per kilowatt of electricity produced by the system are shown for a 10-MW-electric system with recovery of heat as 300° F steam. Both coal-fired systems and a residual-fueled system are shown. Each contractor estimated the costs according to the cost accounts described in section 4.1. The bar graphs include all costs of equipment and installation for a 10-MW-electric system including all fuel-handling, storage, and processing equipment and all heat recovery equipment. Because each cogeneration system produces a different power-to-heat ratio and thus would need a different size and cost supplementary boiler when matched to a common process, bar graphs are also shown that include a supplementary boiler large enough to yield a power-to-heat ratio of 0.25. As indicated by figure 3.2-2, this power-to-heat ratio is near the mean value for all of the processes studied in CTAS.

A comparison of the capital costs for the contractors' coal-fired AFB systems indicates extremely large differences in each of the cost categories. Although the capital costs for category 1 (fuel and waste handling) are much larger for UTC, the capital cost estimate for the GE AFB heat source (category 2) is over a factor of 3 larger than that estimated by UTC. For GE (fig. 5.6-5) some of the capital cost for fuel and waste handling might be included in the AFB heat source cost. A comparison of the total costs for categories 1 and 2 still indicates the GE estimate to be considerably higher. The GE capital cost estimate for the energy conversion system itself (including recuperator) along with heat recovery equipment to raise process steam (category 3) is almost three times the UTC estimate (sum of categories 3A and 3B). There is also a large difference in the capital cost for the supplementary boiler (category 5). In the UTC system the supplementary heat demands are met by increasing the size of the AFB heat source and by adding steam tubes to the bed. GE uses a separate, coal-fired AFB unit for supplementary heat. Although the GE system has a much larger supplementary heat load (34 MW thermal) than the UTC system (13 MW thermal), the resulting costs on a dollars-per-kilowatt-of-thermal-duty basis are substantially different ($15/kW thermal for UTC; $190/kW thermal for GE). Costs represented by category 6 are those associated with heat rejection equipment for the closed-cycle gas turbine. Again, the GE capital cost estimate for this category is about three times UTC's. However, this cost is a very small percentage of the total capital cost for both contractors. Note that a capital cost category for balance of plant (category 7) is not indicated by GE. For the closed-cycle gas turbine systems GE distributed their balance-of-plant costs among the other cost categories. As shown, the balance-of-plant capital cost for UTC constitutes a small percentage of the total capital cost. Differences in cost category 8 (contingency and architect and engineering (A&E) services) are due to two factors. First, since these adders are a certain percentage of the total accumulative costs of the other cost categories, the category 8 costs will reflect differences in these accumulated costs. Second, as mentioned in section 4.2, different percentages were used by the contractors for contingency and A&E services.

Comparison of the capital costs without the costs for the supplementary boiler still indicates a substantial difference in capital cost ($1200/kW electric for UTC; $2540/kW electric for GE).

A capital cost comparison between the coal-fired and liquid-fueled systems studied by UTC is shown in figure 5.6-5. As shown, the coal-fired system is more expensive than the system using coal-derived residual fuel. The primary reason for the higher capital cost of the coal-fired system is its higher fuel and waste-handling costs. The capital cost for the heat source (category 2) is higher for the liquid-fueled system because of the high cost for the ceramic heat exchanger materials that are used to achieve the 2200° F turbine inlet temperature. The capital cost for the closed-cycle gas turbine itself (category 3A) is higher for the coal-fired system because of the added cost of a recuperator; the liquid-fueled system is a simple-cycle configuration. The capital costs for the remaining categories are similar.

5.6.2.4 Economics

The levelized annual operating cost saving versus incremental capital cost is shown in figures 5.6-6 and 5.6-7 for both contractors' closed-cycle gas turbine systems matched with the nine representative industrial processes. Levelized annual operating cost saving is defined as the difference in levelized annual operating costs for fuel, electricity, and operations and maintenance (O&M) between the cogeneration and noncogeneration systems. In each figure the origin corresponds to the noncogeneration situation, where all required electricity is purchased and onsite steam is produced in a residual-fueled boiler. Since the power requirement varies considerably from process to process (table 4.4-1), the incremental capital cost and levelized annual operating cost saving are expressed per unit of site power required. As noted, not all of the cogeneration cases are sized to match the site power requirements. Also shown are lines of constant return on investment (ROI).

More UTC coal-fired systems than GE systems in figure 5.6-6 achieve ROI's greater than 10 percent, primarily because of the lower incremental capital costs of the UTC systems. The incremental capital costs of the export cases are larger than those of the match-power or import cases since the onsite energy conversion system is larger. However, the operating saving in none of these cases is raised sufficiently in comparison with the capital cost increase to make the ROI's of export cases lower than those of corresponding match-power or import cases.

Lower incremental capital costs and lower operating cost savings are indicated for the UTC residual-fueled systems in figure 5.6-7. The annual operating savings are lower than those for the coal-fired systems because of the higher price of fuel used in the gas turbine heat source. The result is generally lower ROI's for the residual-fueled systems.

The other economic parameter used in CTAS to combine the effects of capital and operating cost is the percent savings in levelized annual energy cost, defined in section 2.5. The levelized annual operating cost saving ratios (LAECSR) are shown in figure 5.6-8, for the cogeneration closed-cycle gas turbine systems matched to the nine representative industrial processes. In part (a) only cases that do not involve power export are included; in part (b) all cases are included. In each part of the figure, when there is more than one matching strategy to choose from, the one with highest LAECSR is shown.

The UTC coal-fired systems have significantly higher LAECSR's than their coal-derived-residual-fueled systems because of the lower price of coal. Also, the UTC coal-fired systems have larger LAECSR's than the GE coal-fired systems because of the lower capital costs and higher fuel energy savings of the UTC systems.

The comparison of LAECSR's for cases including export of electricity (fig. 5.6-8(b)) is the same as in part (a) for both contractors. However, the cases including power export have lower LAECSR's than those without. By including export, excess electricity is generated and sold to the utility at 60 percent of the buying price to the industry. However, the increased capital cost component of the levelized annual operating cost and the increased fuel cost more than offset the revenue from the sale of electricity. The export cases would look more attractive economically with a higher sell-back price of electricity.

Comparing the LAECSR's of the coal-fired systems in figure 5.6-8 with the fuel energy saving results in figure 5.6-3 shows that some systems that have a relatively low fuel energy saving have a relatively high LAEC saving. This occurs for several processes with low power-to-heat ratios using match-power strategy such that a large supplementary boiler is needed in the cogeneration case. Because only a part of the process steam used on site is generated from energy-conversion-system waste heat, the fuel energy saving is low. But these results assume the use of residual fuel in the noncogeneration boiler, and both contractors assumed the use of coal to generate supplementary steam when coal is used in the cogeneration systems. Thus, in such cases the operating cost saving is derived from the switch to less expensive fuel rather than from a saving of energy. Since the operating cost is generally the largest contributor to the LAEC, this results in the same effect in terms of LAECSR as does a high fuel energy saving. When the same fuel is assumed to be used in cogeneration and noncogeneration cases, this effect does not occur, but the relationship between LAECSR and FESR is still complicated by the effects of power-to-heat ratio, matching strategy used, and the hours of operation per year. For example, GE's results for coal-fired, closed-cycle gas turbines in the meat packing and malt beverage industries show attractive fuel energy savings but zero LAEC savings. The reason is that the hours per year of plant operation are lower than for the other processes, so that the capital cost contribution to LAEC becomes more dominant. These effects and relationships between the parameters used in CTAS are discussed further in terms of some parametric cases in appendix D.

The data shown in figures 5.6-6 and 5.6-7 generally agree with information shown in figure 5.6-8 concerning which processes yield the most attractive results for each type of closed-cycle gas turbine system. Both indicate that the exclusion of export of electricity and the use of coal as a fuel for the closed-cycle gas turbine system yield more attractive economic results.

5.6.2.5 Relative National-Basis Fuel Saving

Potential national fuel savings as a function of hurdle return on investment are shown in figures 5.6-9 to 5.6-11. The procedure used to calculate these curves is described in section 4.4. It was assumed for each system that it will be 100 percent implemented in new-capacity additions or retirement replacements between 1985 and 1990 in each process where the results yield an

ROI greater than the hurdle rate shown. Results were calculated for the GE systems using 40 of the processes they studied and for the UTC systems using 26 of their processes. No extrapolation beyond these processes was done. These figures are intended to illustrate the comparative potential saving versus ROI requirement and not the absolute magnitude of savings.

Figure 5.6-9 shows the potential fuel savings for the coal-fired, closed-cycle gas turbines. Only cogeneration strategies that do not involve export of power from an individual plant site are included. Note that the UTC results extend to a slightly higher range of ROI than those of GE. The UTC results show some processes that achieve a higher ROI than shown in figure 5.6-6 for the subset of nine processes. For the GE case, the potential national fuel saving, if an ROI greater than 10 percent is required, is only about 10 percent of that if no hurdle ROI is applied. However, for the UTC cases 85 percent of the total potential fuel saving is achieved by processes with ROI's greater than 10 percent. Only two UTC cases exceed 20 percent ROI, and no GE case does so.

The potential fuel savings for the coal-fired systems when power is exported from individual plant sites are shown in figure 5.6-10. The potential national fuel saving shown for low hurdle ROI rates is higher than shown in figure 5.6-9, which does not include export. For this system, using a cogeneration strategy that involves export increases the plant-site fuel energy saving in some cases (fig. 5.6-3) but generally results in lower ROI. The range of ROI for the GE systems is not as high when export is allowed. The range of ROI for the UTC cases is about the same when export is allowed as when it is excluded. For both contractors, however, the potential national fuel savings are the same at high ROI's when export is included as when it is not.

The potential national fuel savings for the residual-fueled, closed-cycle gas turbines as studied by UTC are shown in figure 5.6-11. In part (a), no export of power is considered; in part (b) export of power is included. Higher potential fuel savings are achieved by the residual-fueled systems at low values of hurdle ROI than are attained by the coal-fired systems because of the higher fuel energy savings of the residual-fueled systems (fig. 5.6-3). However, because of the higher price of fuel, the range of ROI attained for the residual-fueled systems is lower than that for the coal-fired systems, as is indicated in figures 5.6-6 and 5.6-7. As a result, at the higher hurdle ROI rates, fewer processes are shown and the aggregated fuel savings at the higher ROI hurdle rates are lower in figure 5.6-11 than for the coal-fired systems in figure 5.6-9.

As shown for the coal-fired systems previously, the potential national fuel savings for the residual-fueled systems allowing export of power (fig. 5.6-11(b)) at low hurdle ROI rates are higher than those where export is not included (fig. 5.6-11(a)). However, the processes appearing in part (b) are generally at lower ROI than those in part (a). As a result at higher hurdle ROI rates the national fuel energy savings in part (b) are lower than those shown in part (a).

5.6.3 Summary

The range of performance results achieved by the closed-cycle gas turbine systems for the nine representative industrial processes is shown in table 5.6-4. For each parameter the industrial process that yields the maximum value is indicated. The fuel energy saving ratio (FESR) for the UTC systems is good, with maximum values in the low 40's for the residual-fueled systems and in the upper 30's for the coal-fired systems. The FESR values for the GE coal-fired systems are not as high, achieving maximum values in the upper teens without export and in the mid 30's with export. The GE systems result in highest FESR when matched to the malt beverage process both with and without power export. The malt beverage process requires some of its process heat in the form of hot water. As shown in figure 5.6-2 and explained earlier, the potential fuel energy saving for the closed-cycle gas turbine increases dramatically when hot water is the process heat requirement because of the opportunity to recover more of the available waste heat from the conversion system. Thus the fuel energy savings tend to be higher for processes that require hot water. For the residual-fueled, closed-cycle gas turbine system studied by UTC, the steel process provides a substantial amount of byproduct fuel gas, which is assumed to be burnable in the conversion system heat source. The use of the byproduct fuel reduces the requirement for purchased residual fuel in the cogeneration case and hence results in higher FESR than the malt beverage or meat packing processes, which require some hot water. For the UTC coal-fired AFB system the maximum value of FESR is attained in the writing paper (bleached Kraft) process. This process requires hot water and provides a byproduct black-liquor fuel, which UTC assumed could be burned in the AFB. The combination of producing process hot water and burning the byproduct fuel results in the maximum FESR.

The emissions saving ratios (EMSR) for the UTC liquid-fueled systems are higher than those for the coal-fired systems because of their higher fuel energy savings and lower emissions rates per unit of fuel burned. The UTC coal-fired systems show higher EMSR than the GE coal-fired systems because of their higher fuel energy savings and the slightly lower rate of NO_x emissions from their AFB as compared with that of GE. The industries in which the highest EMSR values are achieved are those in which the highest fuel energy savings occur.

The (LAEC) levelized annual energy cost saving is dominated by the operating cost saving. Thus the LAECSR values achieved for the UTC coal-fired systems are higher than those for the residual-fueled systems because of the lower price of coal. The UTC coal-fired systems have higher LAECSR than the GE coal-fired systems primarily because of their higher fuel energy savings and their much lower capital costs. There is no increase in LAECSR when including export of electricity since the higher capital cost of the system when exporting electricity more than offsets the revenue from the sale of the excess power. A higher sell-back price for the excess power (60 percent of the utility selling price was assumed) would significantly improve the export cases. For the coal-derived residual systems studied by UTC the highest LAECSR was attained with the chlorine process. In this process byproduct hydrogen fuel is available for use in the energy conversion system, and this reduces the fuel cost portion of the operating cost saving for the cogeneration system. Also, because of the relatively high power-to-heat ratio of the chlorine process the cogeneration match with chlorine results in the import of

electricity. Because the conversion system is sized smaller than the required process power demand, its capital cost is also relatively small. The combination of burning the byproduct fuel and lower capital cost results in the high value of LAECSR. For the UTC coal-fired systems the highest LAECSR's are achieved in the writing paper process because of the high fuel energy saving resulting from the use of byproduct fuel and the requirement for process hot water. Also, for the results shown, the noncogeneration onsite boiler was assumed to use residual fuel. In coal-fired cogeneration systems both contractors assumed that any required supplementary boiler would also use coal. Thus, in low-power-to-heat-ratio processes the LAECSR's are high not only because of a saving in fuel energy due to cogeneration, but also because of a switch to coal rather than more expensive coal-derived residal fuel in the onsite boiler. This is the reason for high LAECSR's in the petroleum processes for both contractors' results (fig. 5.6-8). For GE the highest LAECSR is attained with the petroleum process.

For the UTC coal-derived-residual-fueled systems and the GE coal-fired systems, the industries with maximum ROI are the same as those with maximum LAECSR. For the UTC coal-fired systems the maximum ROI is achieved in the newsprint process. Figure 5.6-6(b) shows the systems match with the newsprint process at a slightly higher value of ROI when using a matching strategy that requires import of electricity, primarily because of the lower capital cost. Table 5.6-4 shows a higher value of ROI for the UTC coal-fired systems relative to the residual-fueled systems because of the lower fuel cost. Also, the UTC coal-fired systems have a higher range of ROI than the GE coal-fired systems primarily because of lower UTC capital cost estimates.

The closed-cycle gas turbine has better cogeneration performance when hot water is required by the process. However, the contractors' industrial data indicate relatively few industries where substantial amounts of hot water are required. Therefore in most cases a substantial amount of heat from the closed-cycle gas turbine is not recovered. In some of the processes that do need hot water (such as the food industry) the hours of operation per year are low. The operating cost savings per year are therefore lower than had the processes been at higher load factors, and thus the economic results are not attractive.

The GE results for the closed-cycle gas turbine are, overall, less attractive than the UTC results for two reasons. First, GE used an 80° F compressor inlet temperature, and UTC assumed either a 190° F or 300° F inlet temperature. Although the lower compressor inlet temperature does result in higher electrical efficiency, it also causes a lower fraction of the system waste heat to be recovered for process use. For the GE cases this resulted in higher system power-to-heat ratios and lower potential fuel energy savings and, thus lower overall performance. Second, the capital cost estimates for the GE closed-cycle gas turbines are much higher than those of UTC. This has its most prominent effect on the return on investment. The high capital cost estimates by GE, along with lower fuel energy savings mentioned previously, result generally in lower ranges of ROI and in fewer cogeneration cases attaining ROI's greater than 10 percent.

TABLE 5.6-1. - ENERGY CONVERSION SYSTEM PARAMETERS AND CONFIGURATION STUDIED FOR CLOSED-CYCLE GAS TURBINE SYSTEMS

Parameter	General Electric Co.		United Technologies Corp.	
	Working fluid			
	Helium	Air	Helium	Air
Turbine inlet temperature, °F	1500	---	1500	1500
Recuperator effectiveness, E_r	0, 0.6, 0.85	---	0, 0.85	0, 0.85
Pressure ratio	(a)	---	3	3,6
Compressor inlet temperature, °F	80	---	190	[b]190 [c]300
Turbine inlet temperature, °F	-------	---	2200	2200
Recuperator effectiveness, E_r	-------	---	0, 0.85	0, 0.85
Pressure ratio	-------	---	[c]6 [d]4	[c]6, [c]14 [d]6
Compressor inlet temperature, °F	-------	---	190	190

[a]Unknown.
[b]Recuperator effectiveness, E_r = 0 and 0.85.
[c]E_r = 0.
[d]E_r = 0.85.

TABLE 5.6-2. - DESIGN OPTIONS FOR UNITED TECHNOLOGIES CORP. CLOSED-CYCLE GAS TURBINE SYSTEMS

(a) Coal-fired AFB systems

Design option	Recuperator effectiveness	Working fluid	Compressor pressure ratio	Compressor inlet temperature, °F
1	0	Air	6	190
2	0	Air	6	300
3	.85	Air	6	190
4	0	Helium	3	190
5	.85	Helium	3	190

(b) Coal-derived-residual-fueled systems

Design option	Recuperator effectiveness	Working fluid	Compressor pressure ratio	Compressor inlet temperature, °F
1	0.85	Air	6	190
2	0	Air	6	↓
3	0	Air	14	↓
4	.85	Helium	4	↓
5	0	Helium	6	↓

TABLE 5.6-3. - EMISSIONS FOR CLOSED-CYCLE GAS TURBINE SYSTEMS

Pollutant	Fuel		
	Coal (AFB)		Coal-derived residual (UTC)
	GE	UTC	
	Emissions, lb/10^6 Btu		
Oxides of sulfur	1.2	1.2	0.824
Oxides of nitrogen	.36	.2	.5
Particulates	.1	.1	.1
Total	1.66	1.5	1.424

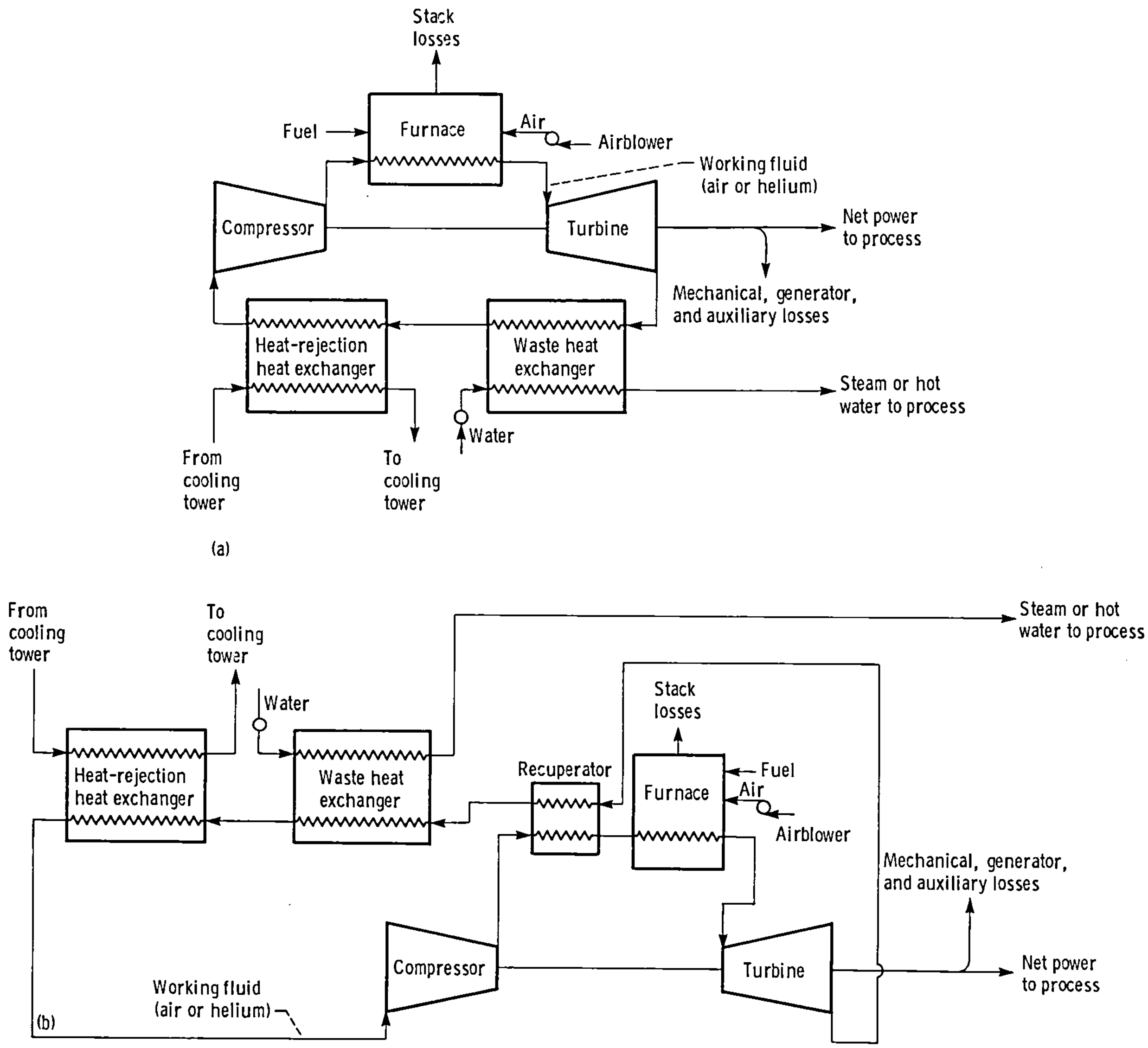
TABLE 5.6-4. - RANGE OF RESULTS FOR CLOSED-CYCLE GAS TURBINE SYSTEMS USED WITH NINE REPRESENTATIVE INDUSTRIES

(a) No power export allowed

Energy conversion system subgroup	Contractor	Fuel energy saving ratio, FESR	Industry with maximum FESR	Emissions saving ratio, EMSR	Industry with maximum EMSR	Levelized annual energy cost, LAEC	Industry with maximum LAEC	Return on investment, ROI, percent	Industry with maximum ROI
Closed-cycle gas turbine/ coal-derived residual	UTC	15.0-41.2	Steel	18.8-58.2	Steel	Negative to 15.7	Chlorine	4.9-14.4	Chlorine
Closed-cycle gas turbine/ AFB	GE	3.7-19.7	Malt beverage	13-28	Malt beverage	Negative to 21.3	Petroleum	0-15	Petroleum
	UTC	6.8-37.6	Writing paper	11.1-48.0	Writing paper	6.7-35.2	Writing paper	0-20	Newsprint

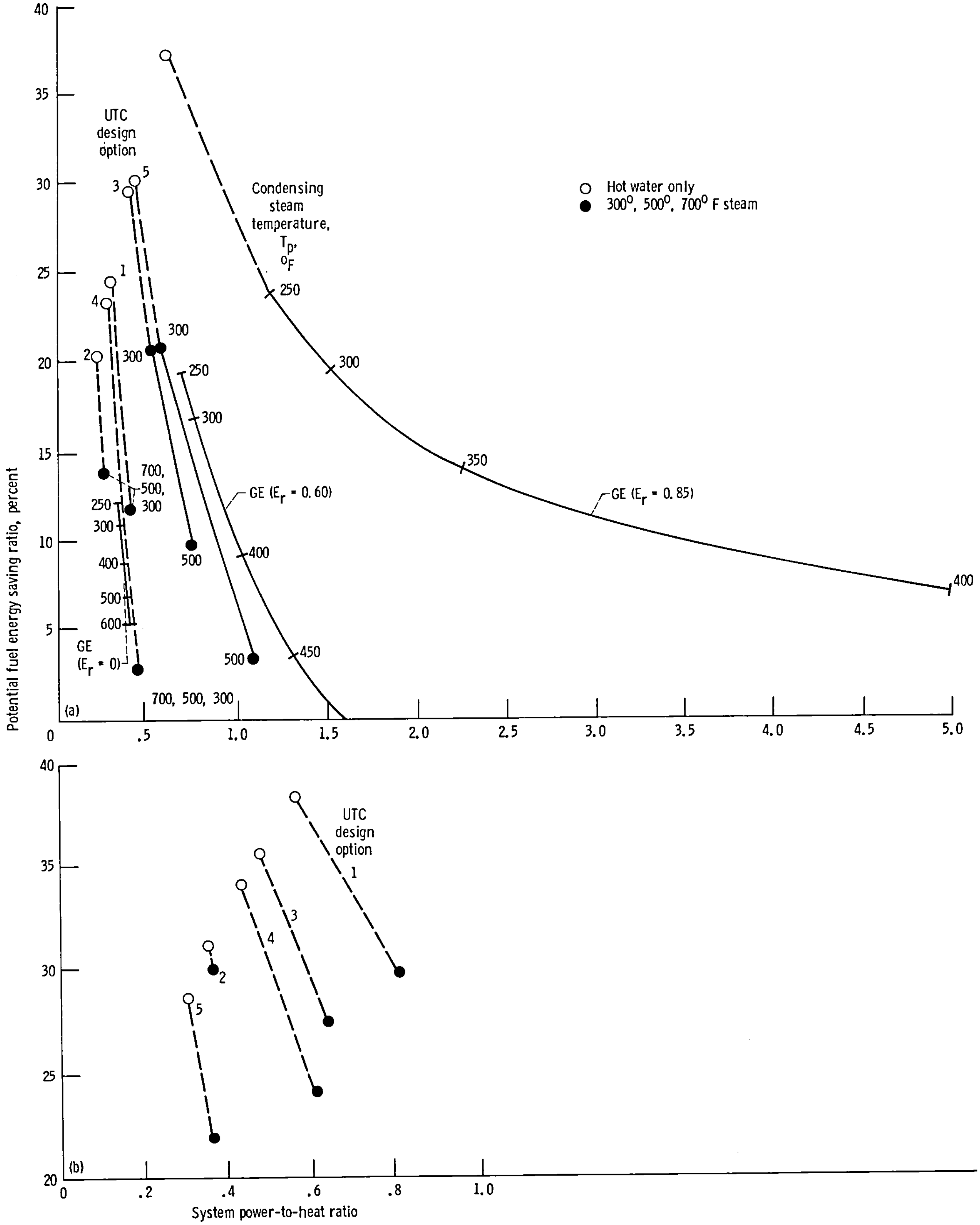
(b) Power export allowed

Closed-cycle gas turbine/ coal-derived residual	UTC	15.0-41.2	Steel	18.8-58.2	Steel	Negative to 15.7	Chlorine	0-14.4	Chlorine
Closed-cycle gas turbine/ AFB	GE	3.7-33.7	Malt beverage	13-39	Malt beverage	Negative to 21.3	Petroleum	0-15	Petroleum
	UTC	6.8-37.6	Writing paper	11-48	Writing paper	6.7-35.2	Writing paper	0-20	Newsprint



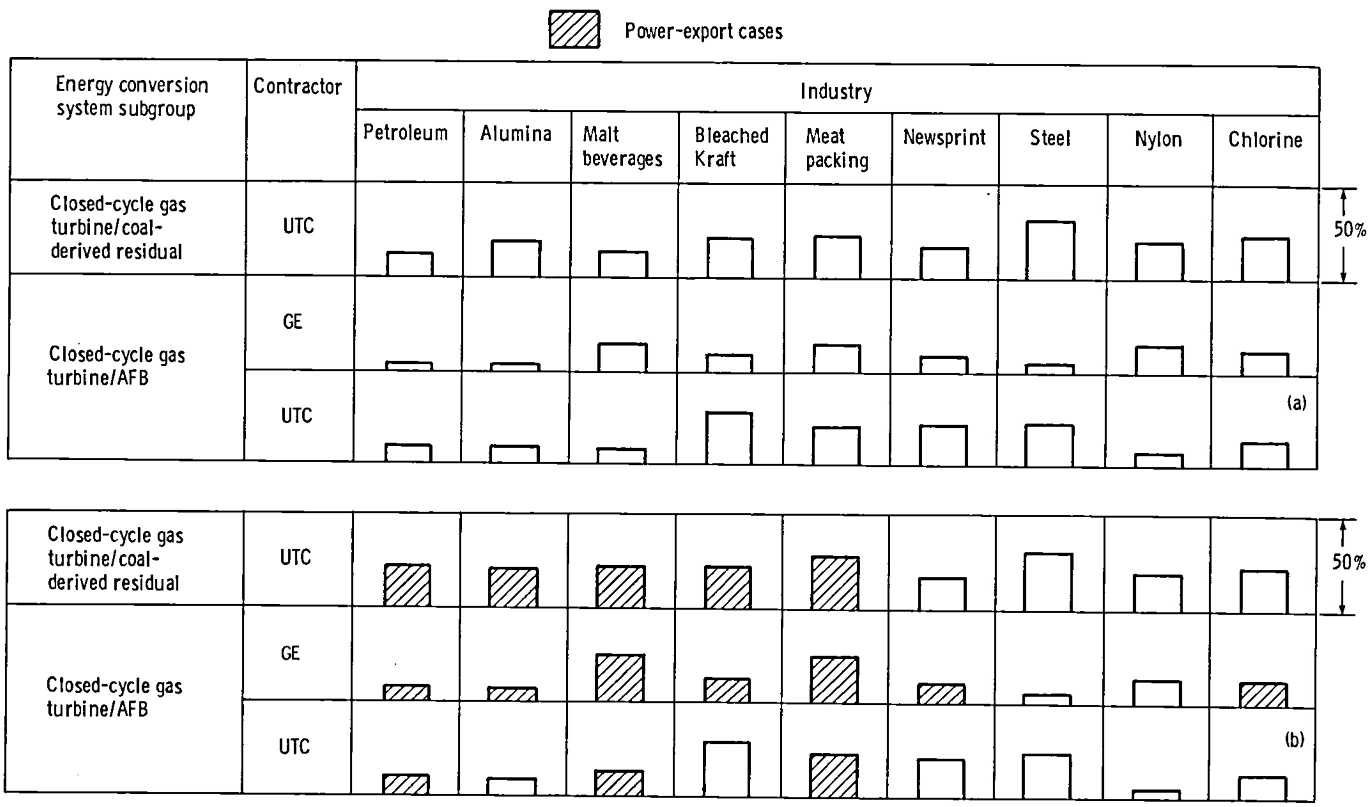
(a) Simple cycle.
(b) Recuperated cycle.

Figure 5.6-1. - Schematics of closed-cycle gas turbine systems.



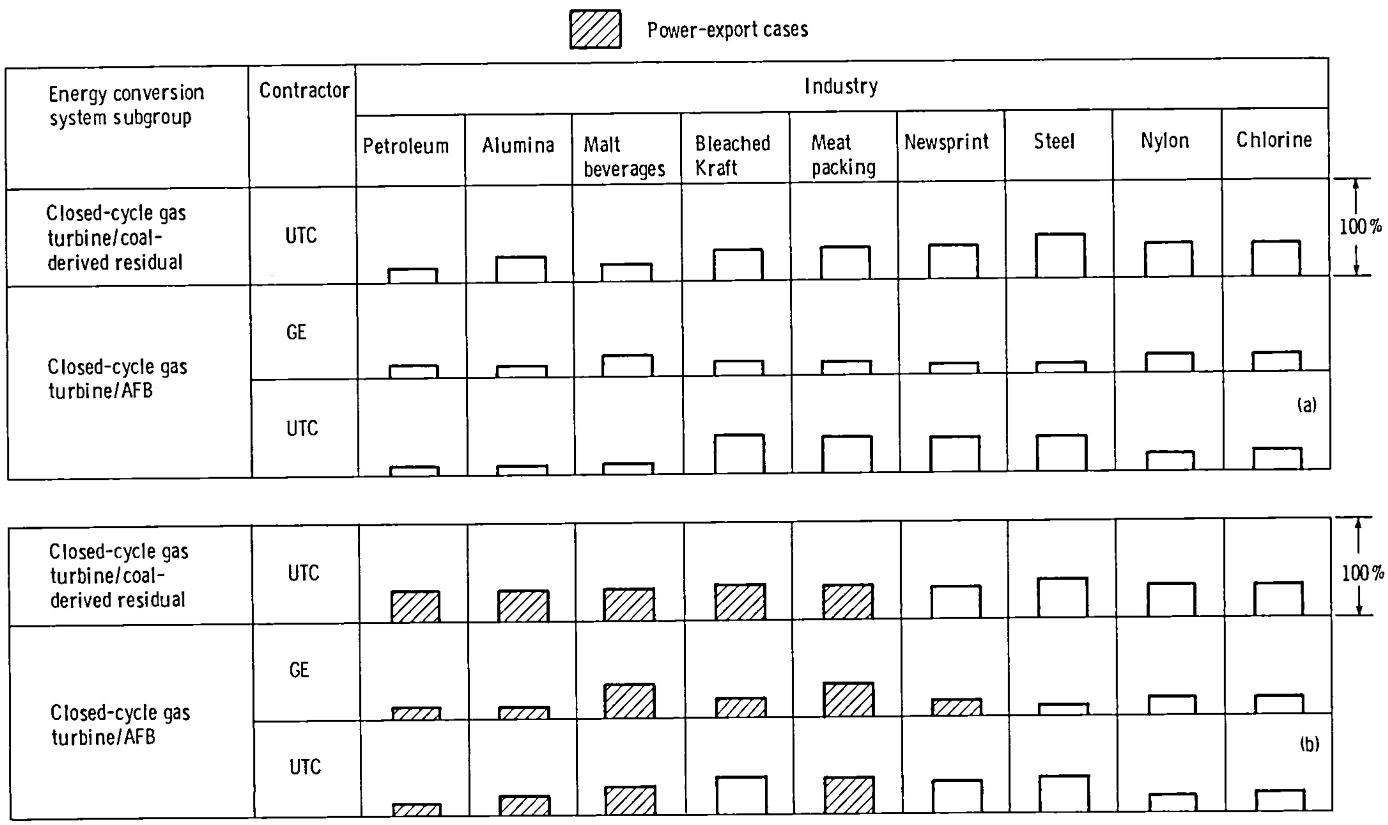
(a) Coal-fired system (AFB).
(b) Coal-derived-residual-fueled system.

Figure 5.6-2. - Potential fuel energy saving ratios for closed-cycle gas turbine systems.



(a) No power export allowed.
(b) Power export allowed.

Figure 5.6-3. - Fuel energy saving ratio for closed-cycle gas turbine systems.



(a) No power export allowed.
(b) Power export allowed.

Figure 5.6-4. - Emissions saving ratios for closed-cycle gas turbine systems.

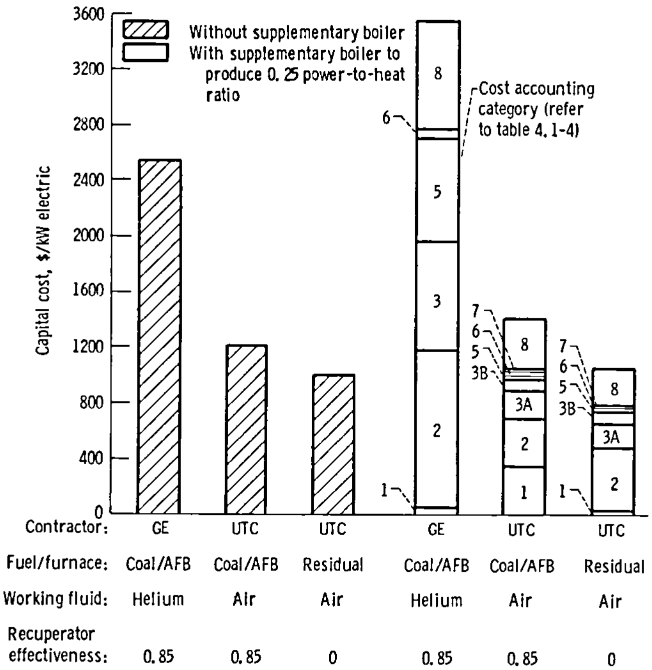
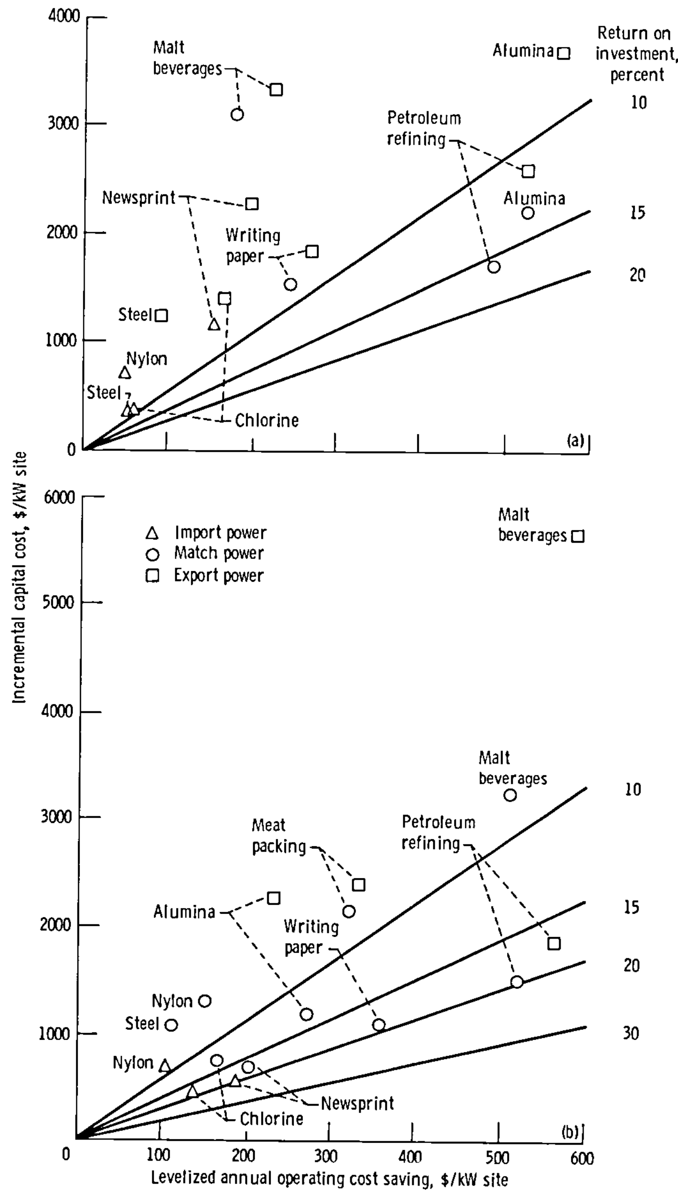


Figure 5.6-5. - Capital costs for closed-cycle gas turbine systems. Electricity generated, 10 MW; process steam temperature, 300° F. (Other balance-of-plant costs (category 7) included in GE islands 1, 2, 3, 5, and 6.)



(a) GE.
(b) UTC.

Figure 5.6-6. - Incremental capital cost as a function of levelized annual operating cost saving for closed-cycle gas turbine/AFB systems.

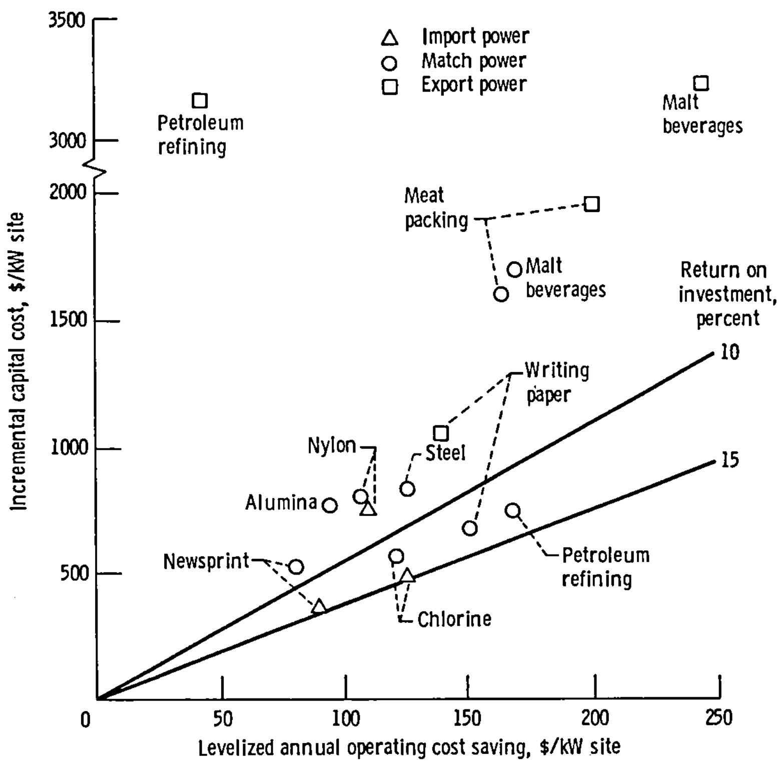
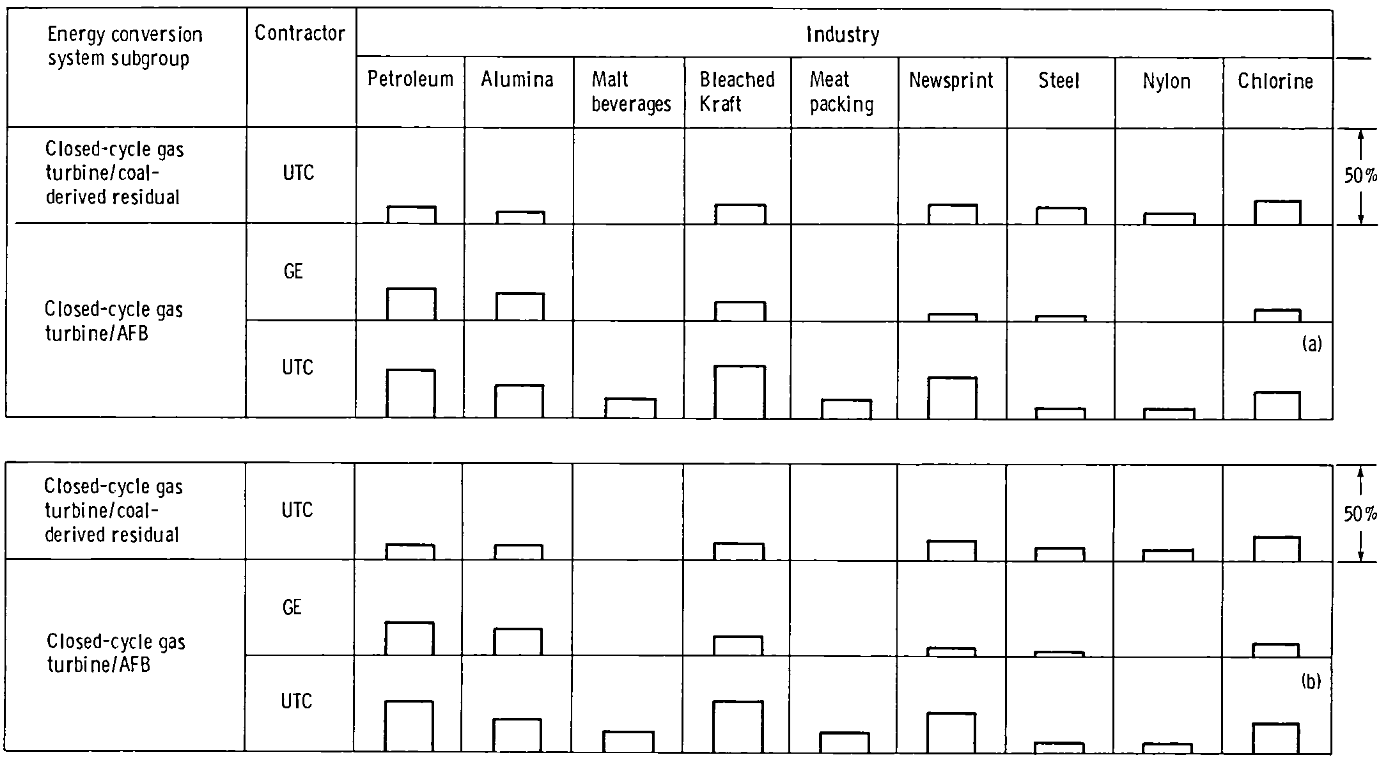
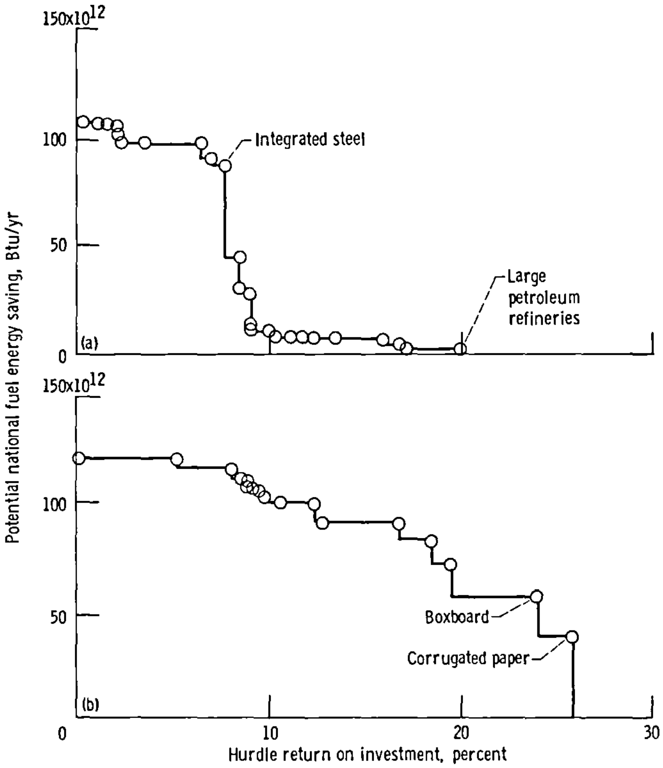


Figure 5.6-7. - Incremental capital cost as a function of levelized annual operating cost saving for UTC's closed-cycle gas turbine/coal-derived residual system.



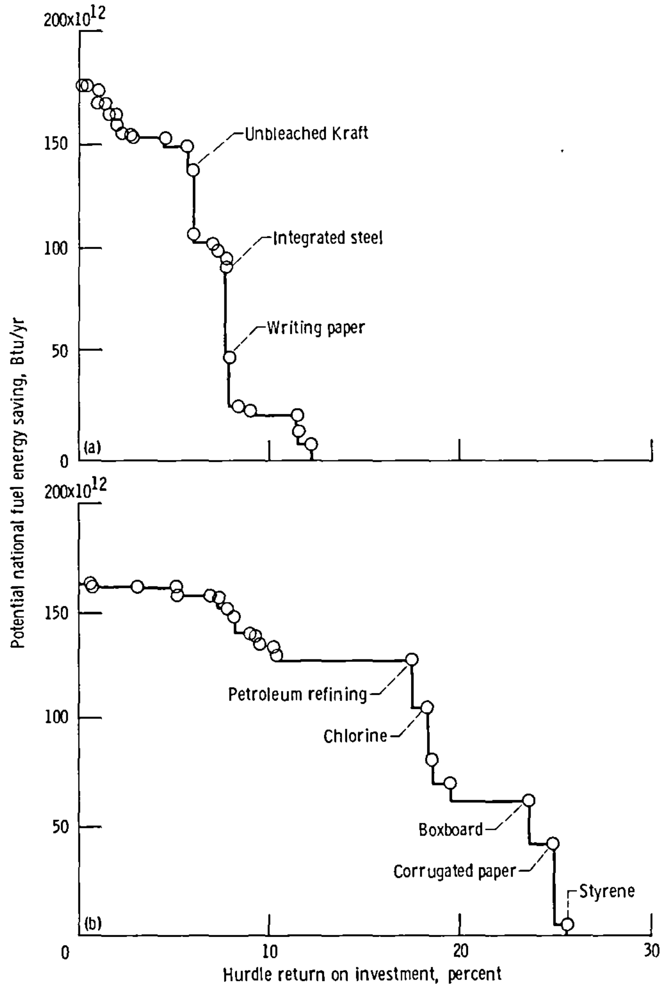
(a) No power export allowed.
(b) Power export allowed.

Figure 5.6-8. - Levelized annual energy cost saving ratios for closed-cycle gas turbine systems. (Blanks denote all negative values.)



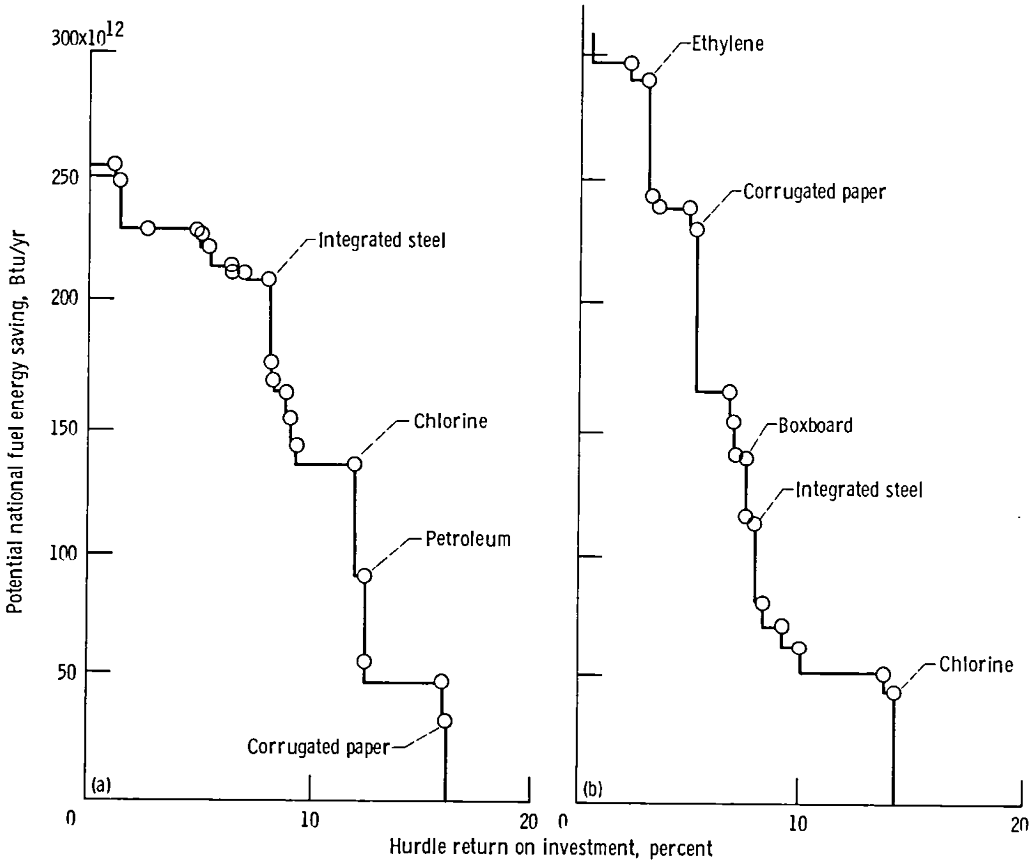
(a) GE.
(b) UTC.

Figure 5.6-9. - Potential national fuel energy saving as a function of hurdle return on investment for closed-cycle gas turbine/AFB systems with no power export allowed.



(a) GE.
(b) UTC.

Figure 5.6-10. - Potential national fuel energy saving as a function of hurdle return on investment for closed-cycle gas turbine/AFB systems with power export allowed.



(a) No power export allowed.
(b) Power export allowed.

Figure 5.6-11. - Potential national fuel energy saving as a function of hurdle return on investment for UTC's closed-cycle gas turbine/coal-derived residual system.

5.7 PHOSPHORIC ACID FUEL CELL SYSTEMS

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5.7.1 Configurations and Parameters

Parameters and configurations of the phosphoric acid fuel cell power systems studied by each contractor are listed in table 5.7-1. General Electric studied atmospheric-pressure fuel cell systems with a steam reformer. United Technologies studied pressurized fuel cell systems with a steam reformer for systems using petroleum-derived distillate fuel and with an adiabatic reformer for systems using coal-derived distillate fuel.

Block diagrams of the phosphoric acid fuel cell power systems studied by the contractors are shown in figure 5.7-1. GE considered a single configuration (fig. 5.7-1(a)). Among the system configurations considered by UTC, the one (system 28, design option 2) shown in figure 5.7-1(b) shows the most attractive performance and economic results. Comparison of these two configurations indicates three major differences that offset system performance and in turn affect cost.

The first difference is the source of steam required in the fuel-reforming process. GE heats hot water with fuel cell waste heat. A part of the hot water is heated to steam for the fuel reformer by using the waste heat in the fuel-reformer burner exhaust. The steam used in fuel reforming is not available for industrial processes. The remaining hot water is available for industrial processes. UTC uses cathode exhaust gas for fuel reforming after its temperature is raised to near the reformer reaction temperature by hot fuel gas. The cathode exhaust consists of product water in vapor form and unreacted oxygen. This approach makes available the steam generated by the fuel cell waste heat for industrial processes.

The second difference comes from the different fuel cell operating conditions. The UTC system with the pressurized fuel cell requires an air-compressor turbine and operates at a slightly higher temperature than the GE fuel cell. The GE system operating at atmospheric pressure supplies air with a fan and does not require an air-compressor turbine.

The third difference is in the arrangement of the heat exchangers and the temperature of the waste heat used for the generation of process steam. Two GE steam-generating heat exchangers use waste heat at temperatures above 1100° F. From the performance characteristics of the GE phosphoric acid fuel cell (discussed in the next section), it is apparent that the heat exchangers operating with low-temperature waste heat are connected to the high-temperature heat exchangers in series to generate steam at temperatures over a wide range required by industrial processes for a constant high recovery of waste heat. In the UTC configuration the high-quality heat in the fuel gas is used to raise the temperature of the cathode exhaust gas prior to its use in the reformer. Because of this configuration the UTC fuel cell system uses waste heat at relatively low temperatures for process steam generation and generates most steam at 300° F.

Another difference is related to the first and the third differences discussed above and is what is produced by using the fuel cell waste heat for processes. The GE system generates hot water; the UTC system generates steam.

The effects of configurations and parameters on the performance and economic results are discussed in the next section. The GE configuration produces higher temperature steam and would therefore be expected to yield cogeneration performance results that are less sensitive to the process steam temperature requirements. Also the GE system would be expected to yield a higher power-to-heat ratio than the UTC system when the process requires only low-pressure steam. The low-quality heat in the cathode exhaust is not recovered because a part of the generated steam is used in the fuel reformer, and the fuel cell waste heat is used to raise hot water as shown in figure 5.7-1.

5.7.2 <u>Cogeneration System Performance</u>

5.7.2.1 Fuel Energy Saving Ratio

The power-to-heat ratios produced for a range of process steam conditions are shown in figure 5.7-2, together with the potential fuel energy savings that would be achieved if the fuel cell system exactly satisfied the process power and thermal needs without either operation of a supplementary boiler or import or export of power. As discussed in appendix D, if the site-required power-to-heat ratio differs from the ratio provided by the energy conversion system, the fuel savings in most cases will be lower than indicated. Performance potentials of the two systems agree closely with each other when only hot water is required for the industrial process. The two systems show a significant performance difference when steam is required for the industrial process. This difference is due to differences in the design approach pointed out in the previous section.

The performance potential of the GE phosphoric acid fuel cell system drops significantly when hot water is not required because a large amount of heat that can be recovered in the form of hot water in the fuel cell cooling condenser and the anode exhaust condenser is not used to provide process steam. The GE system therefore shows a relatively large power-to-heat ratio of 2.24 when only steam is required. As shown in figure 5.7-1(a) GE process steam is generated at temperatures up to 600° F by the sensible heat in the hot fuel gas and the burner exhaust gas. Therefore the amount of heat recovered and the cogeneration system performance are unchanged for process steam requirements from 250° to 600° F. As shown in figure 5.7-1(b) the UTC system produces process steam by recovering waste heat at relatively lower temperatures, and the amount of heat recovery is therefore more affected by process steam temperature requirements.

The UTC system shows a substantially lower power-to-heat ratio and a higher fuel energy saving when only 300° F steam is required for an industrial process. The UTC system generates ample 300° F steam from the fuel cell waste heat, the waste heat in the fuel gas, and the cathode exhaust in the reformer. The GE system produces hot water from the fuel cell waste heat and uses steam for the fuel reformer. The UTC system shows a larger power-to-heat ratio than the GE system if a process needs only 500° F steam and if the hot water and 300° F steam generated by the UTC system are not used.

The fuel energy saving ratio (FESR) results for the phosphoric acid fuel cell systems matched to the nine representative industries are shown in figure 5.7-3. The characteristics of these processes are listed in

section 3.2. The FESR results are affected by the site-required power-to-heat ratio, the process steam temperature, and the use of byproduct fuel. The FESR results for the no-power-export cases (fig. 5.7-3(a)) are greatly affected by the site-required power-to-heat ratio, especially in the GE results. The GE system achieves higher FESR as the process power-to-heat ratio increases because the system produces a high ratio (2.24) and therefore is a better match with the industries. Also, the GE system performance is not sensitive to process steam temperatures under 600° F. The highest FESR achieved by UTC is due mainly to the maximum use of the byproduct fuel in the supplementary boiler. Because of the difference in the power-to-heat ratio between the system and the process, the system is only able to supply one-third (mostly in 300° F steam) of the total process heat required by the writing paper industry when power is matched. The additional two-thirds of the total process heat (in the form of 500° F steam) is provided by the supplementary boiler, which burns free byproduct fuel. The UTC system matched with the meat packing industry shows a high FESR because it is a closer match in power-to-heat ratio with the system and requires only hot water and 300° F steam, for which the UTC system performance is high. Although the overall power-to-heat ratio of the news- print industry (0.68) is closely matched with the ratio of the UTC system (0.67), the FESR with this process is somewhat lower than that achieved with the writing paper process. There exists a mismatch for each temperature level of the steam requirement, and less byproduct fuel is used to generate some of the 500° F steam required by the process. UTC's newsprint industry needs more steam at 500° F than at 300° F, but the UTC fuel cell system generates more steam at 300° F than at 500° F.

The steel, nylon, and chlorine industries require power-to-heat ratios that are greater than the UTC system ratios, and they show lower FESR values than achieved in the writing paper, meat packing, and newsprint industries. When power is matched in these cases, the UTC fuel cell system generates more thermal heat than is needed by the process. Attractively high FESR for the chlorine process is achieved by the fuel cell system because UTC assumed the use of more byproduct fuel in the UTC phosphoric acid fuel cell than is used in the noncogeneration onsite boiler. UTC results for the petroleum, alumina, and integrated-steel industries were modified by NASA to exclude effects of the direct-heat requirement on cogeneration results. The direct heat specified by UTC for integrated steel is the heat that could be provided by the coking coal. The UTC alumina case requires burning a specified clean fuel for the direct heat to calcine the alumina. The UTC petroleum case also requires a substantial amount of direct heat. For the integrated-steel cases NASA used the byproduct fuel (coke oven gas and blast furnace gas) in onsite boilers for process steam but not in the pressurized fuel cell. Because of this constraint in the use of the byproduct fuel the noncogeneration case used more free by-product fuel than the cogeneration case and as a result had a relatively low FESR. Performance (FESR and EMSR) and economic results were changed as required for the NASA modification.

The FESR results, when power-export cases are included, are shown in figure 5.7-3(b). Power is exported in cases where the process requires a lower power-to-heat ratio than that produced by the system when it is sized to match the site heat requirement or to provide more heat than provided by the match-power strategy. These cases show improved FESR results from the no-power-export cases because of the greater waste heat recovery.

5.7.2.2 Emissions Saving Ratio

The emissions saving ratio (EMSR) results are shown in figure 5.7-4. The results are the sum of NO_x, SO_x, and particulate emissions. The EMSR values are related to the FESR values because higher FESR means less fuel use. The UTC results are the results of their system 28, design option 2, discussed in section 5.7.1. EMSR values are generally high because the phosphoric acid fuel cell system uses a clean distillate fuel, displacing the use of both coal at the utility site and residual fuel in the noncogeneration onsite boiler.

Table 5.7-2 shows the emissions per unit of fuel consumed by the energy conversion systems. For the coal-derived-distillate-fueled system UTC assumed the use of a regenerable metal oxide for removal of sulfur from the fuel gas downstream of the fuel reformer. The sulfur dioxide is then released on site when metal oxide is regenerated. For the UTC petroleum-derived-distillate-fueled system and GE systems using both fuels, the contractors assumed the use of a disposable zinc oxide sulfur removal system located upstream of the fuel reformer. Thus the sulfur dioxide site emissions are assumed to be negligible. The higher EMSR values in figure 5.7-4(b) are due to less use of coal at the utility site.

5.7.2.3 Capital Cost

Figure 5.7-5 compares contractor estimates of installed capital cost for 10-MW-electric phosphoric acid fuel cell systems. Capital cost with a supplementary boiler to produce 300° F steam at 0.25 power-to-heat ratio and capital cost without the supplementary boiler are shown in the figure. When the supplemental boiler cost is not included, the cost estimates of the two contractors are in close agreement.

The total capital costs are broken down into the eight cost categories described in section 4.1. A substantial cost difference for category 5 for the supplementary boiler is shown because the GE system requires a larger supplementary boiler than the UTC system as a result of the significantly higher power-to-heat ratio produced by the GE system. In addition to the boiler size difference the GE cost estimate ($/kW thermal duty) for the onsite boiler burning liquid fuel is substantially higher than the UTC cost estimate.

5.7.2.4 Economics

Incremental capital cost versus levelized operating cost savings is shown in figure 5.7-6 for the phosphoric acid fuel cell systems matched with the nine representative industries. Also shown in the figure are lines of constant return on investment (ROI). The origin corresponds to the noncogeneration situation, where required electricity is purchased and onsite steam is produced in a residual-fueled boiler. The incremental capital costs and operating cost savings are expressed per unit of site power required. None of the GE cases yields an operating cost saving and therefore none appears in the figure in spite of the fact that fuel energy savings are shown in figure 5.7-3. This is due to two factors. First, GE assumed that supplementary boilers use the same type of fuel as used by the energy conversion system; UTC assumed that supplementary boilers use residual fuel. Thus the operating costs of GE distillate-fueled cogeneration systems are higher because of the requirement of a larger supplementary boiler and the higher supple-

mentary boiler fuel price. Second, GE's estimates of operation and maintenance (O&M) costs are significantly higher than UTC's. In some cases, there is an operating cost saving in terms of fuel and electricity costs alone, but when O&M costs are included in cogeneration operation, costs are higher than those for noncogeneration operation. GE estimates for maintenance, labor, and materials are higher primarily because of the replacement cost of the disposable zinc oxide. UTC chose to use a regenerable sulfur cleanup system.

Even though the UTC phosphoric acid fuel cell system has relatively low incremental capital cost and achieves high FESR values in several industries, it does not achieve high ROI's. The reason is the low operating cost saving caused by the use of the expensive distillate fuel. Among the nine industries of the representative subset, only the writing paper industry shows an ROI greater than 10 percent. This UTC case uses a substantial amount of free byproduct fuel in the supplementary boiler to produce the higher temperature steam that the conversion system could not provide. UTC's meat packing industry, which requires hot water and relatively low-temperature steam, achieves a high FESR but an ROI of less than 10 percent as the result of a low operating cost saving caused by a low capacity factor. UTC's malt beverage industry requires only 300° F steam, but it does not achieve a high ROI because of the high degree of mismatch with the phosphoric acid fuel cell system and a relatively low capacity factor.

The other economic parameter used in the CTAS to combine the effects of capital and operating costs is the percent savings in levelized annual energy cost, discussed in section 4.3. Figure 5.7-7 shows the levelized annual energy cost saving ratios (LAECSR) for the nine representative industries. The GE system shows negative LAECSR's for all nine industries for the same reason that the ROI is negative in all cases. That is, the operating cost savings are negative because expensive distillate-grade fuel is used and the O&M cost estimate is higher. The UTC system also shows either negative or very small LAECSR's. As shown in the previous figure the operating cost savings are relatively low. Results shown in part (b) of the figure are identical to the results shown in part (a) because power-export cases result in lower LAECSR's than cases with no power export.

5.7.2.5 Relative National-Basis Fuel Saving

A plot of energy saving aggregated to a national basis as a function of hurdle ROI is shown in figure 5.7-8. Only UTC results are shown. As explained previously, no positive ROI's are achieved by the GE phosphoric acid fuel cell systems in any processes considered. The procedure used to evaluate these curves is described in section 4.4. It was assumed that the phosphoric acid fuel cell system will be implemented 100 percent in new-capacity additions or retirement replacements between 1985 and 1990 for each process where the ROI is greater than the hurdle rate. Only processes specifically studied by each contractor are considered. These figures are intended to illustrate the comparative potential saving versus ROI requirement and not the absolute magnitude of savings. Only the results for match-power cases are shown.

Note that the maximum ROI shown in figure 5.7-8, which includes all of the processes studied by UTC, is the same as that indicated in figure 5.7-6. Only the match-power strategy is included since in all cases this was more

economic than the strategy that involved power export. The UTC results indicate that about one-half of the potential national energy saving for zero hurdle rate is achieved by the phosphoric acid fuel cell systems in the paper industries at ROI values greater than 10 percent.

5.7.3 Summary

The range of results achieved by the phosphoric acid fuel cell systems for the nine representative industries is presented in table 5.7-3. The fuel energy saving ratios (FESR) range from low to high values. When no power export is allowed, the FESR depends mainly on the degree of the system match with the industrial processes. Industries with low power-to-heat ratios show low FESR's because of larger degrees of mismatch between the system and the process, as explained in appendix D, but their FESR's increase if power export is allowed.

The GE phosphoric acid fuel cell system has negative levelized annual energy cost saving ratios (LAECSR) and zero return on investment (ROI) values for all processes considered. The UTC results show some cases with positive LAECSR's and ROI's. This is due to the relatively high O&M cost estimates by GE and their use of distillate fuel in both the fuel cell system and the supplementary boiler. The higher GE O&M cost is due primarily to replacement cost of the disposable zinc oxide. UTC assumed the use of a regenerable sulfur cleanup system for the coal-derived distillate cases. The UTC case (system 28, design option 3) also shows a substantially lower O&M cost estimate than the GE estimate because of the use of residual fuel in the supplementary boiler. The other UTC case considers sulfur removal with disposable zinc oxide and uses naphtha as the fuel. It has a low O&M cost because of the low sulfur content in the fuel. The highest LAECSR and ROI are achieved in the writing paper process. In this process free byproduct fuel is used in the supplementary boiler to produce the higher pressure steam required by the process, and the fuel cell provides the low-pressure steam through waste heat recovery.

The phosphoric acid fuel cell systems show very high emissions saving ratios in most industries because of the relatively clean fuel and the fuel processing and cleanup system that is required by the fuel cell and the fuel reformer. Differences between the contractors' estimates of SO_x emissions for the coal-derived-distillate-fueled cases follow from an assumption of the use of a regenerable metal oxide cleanup by UTC with release of SO_x on site and the use of a disposable zinc oxide system by GE. This difference also significantly affects the comparison of O&M cost estimates and hence economic results.

The economic results for the GE phosphoric acid fuel cell system could be improved by using residual fuel instead of distillate fuel in the supplementary boiler. UTC's approach of using the cathode exhaust gas utilizes even the low-quality heat in the cathode exhaust that is not otherwise recoverable with steam generation and yields better cogeneration results even though the electrical efficiency of the fuel cell system is lower.

TABLE 5.7-1. - ENERGY CONVERSION SYSTEM PARAMETERS STUDIED FOR PHOSPHORIC ACID FUEL CELL SYSTEMS

Parameter	General Electric Co.	United Technologies Corp.
Fuel	Distillate	Distillate
Cell stack temperature, °F	375	400
Cell stack pressure, psia	14.7	120
Fuel processing	Steam reformer	Steam reformer for petroleum-derived distillate (system 27)
		Adiabatic reformer for coal-derived distillate (system 28)
	Use steam in reforming	Use cathode exhaust (system 28, design option 2)
		Use steam (other designs)
Air-compressing turbine	Not required for atmospheric fuel cell	Run by burner exhaust gas
Fuel cleanup	ZnO (nonregenerable)	Regenerable metal oxides with adiabatic reformer
		ZnO (nonregenerable) with steam reformer

TABLE 5.7-2. - EMISSIONS FOR PHOSPHORIC ACID FUEL CELL SYSTEMS

Pollutant	Fuel			
	Petroleum-derived distillate		Coal-derived distillate	
	GE	UTC	GE	UTC
Oxides of sulfur	0	0	0	0.57
Oxides of nitrogen	.027	.016	.39	.42
Particulates	0	0	0	.034

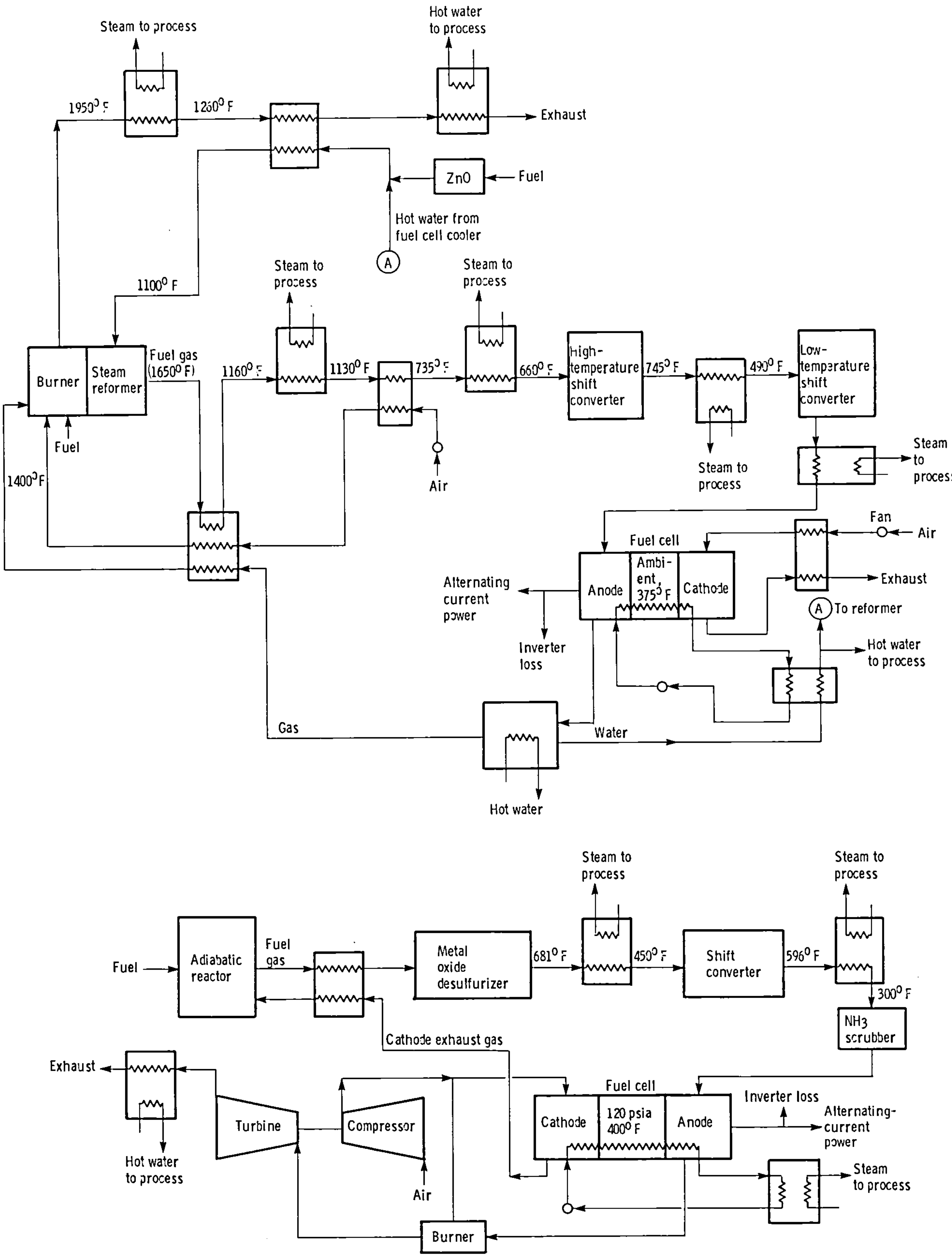
TABLE 5.7-3. - RANGE OF RESULTS FOR PHOSPHORIC ACID FUEL CELL DISTILLATE SYSTEMS USED WITH NINE REPRESENTATIVE INDUSTRIES

(a) No power export allowed

Contractor	Fuel energy saving ratio, FESR	Industry with maximum FESR	Emissions saving ratio, EMSR	Industry with maximum EMSR	Levelized annual energy cost, LAEC	Industry with maximum LAEC	Return on investment, ROI, percent	Industry with maximum ROI
GE	7-28	Steel	All negative	--------	52-83	Nylon	All 0	--------
UTC	2-36	Writing paper	Negative to 11	Writing paper	8-73	Chlorine	0-14	Writing paper

(b) power export allowed

Contractor	Fuel energy saving ratio, FESR	Industry with maximum FESR	Emissions saving ratio, EMSR	Industry with maximum EMSR	Levelized annual energy cost, LAEC	Industry with maximum LAEC	Return on investment, ROI, percent	Industry with maximum ROI
GE	7-38	Malt beverage	All negative	--------	52-87	Malt beverage	All 0	--------
UTC	2-40	Writing paper; meat packing	Negative to 11	Writing paper	8-80	Meat packing	0-14	Writing paper



(a) GE.
(b) UTC (system 28, design option 2).

Figure 5.7-1. - Schematics of phosphoric acid fuel cell systems.

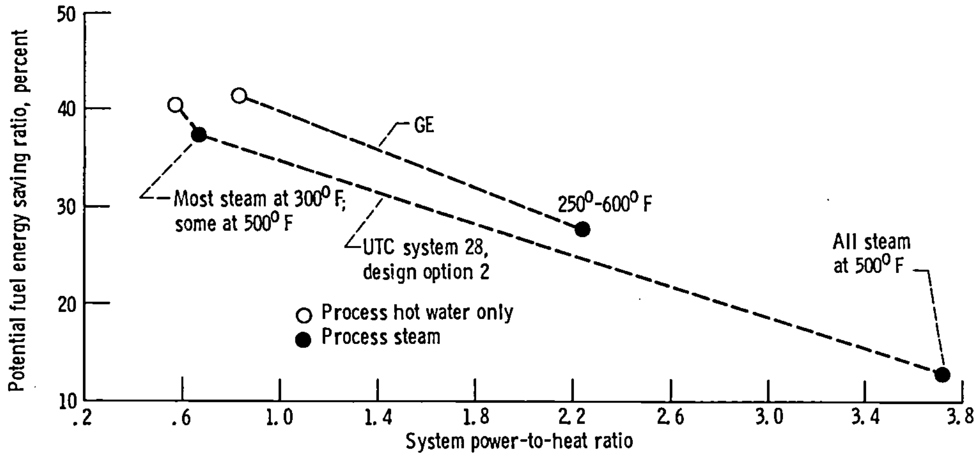
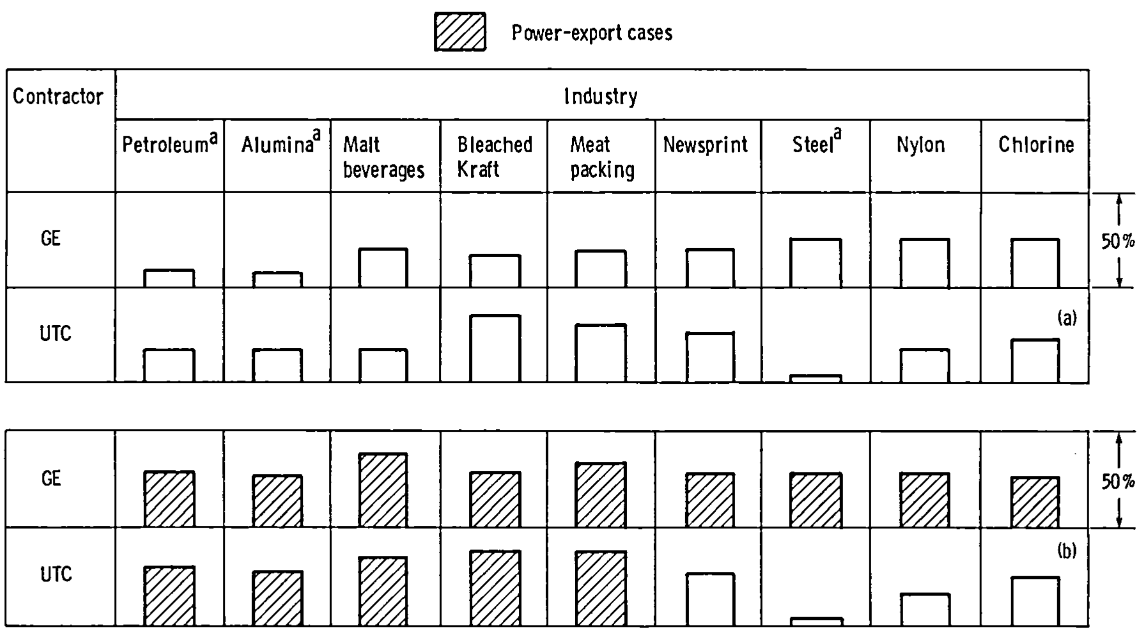


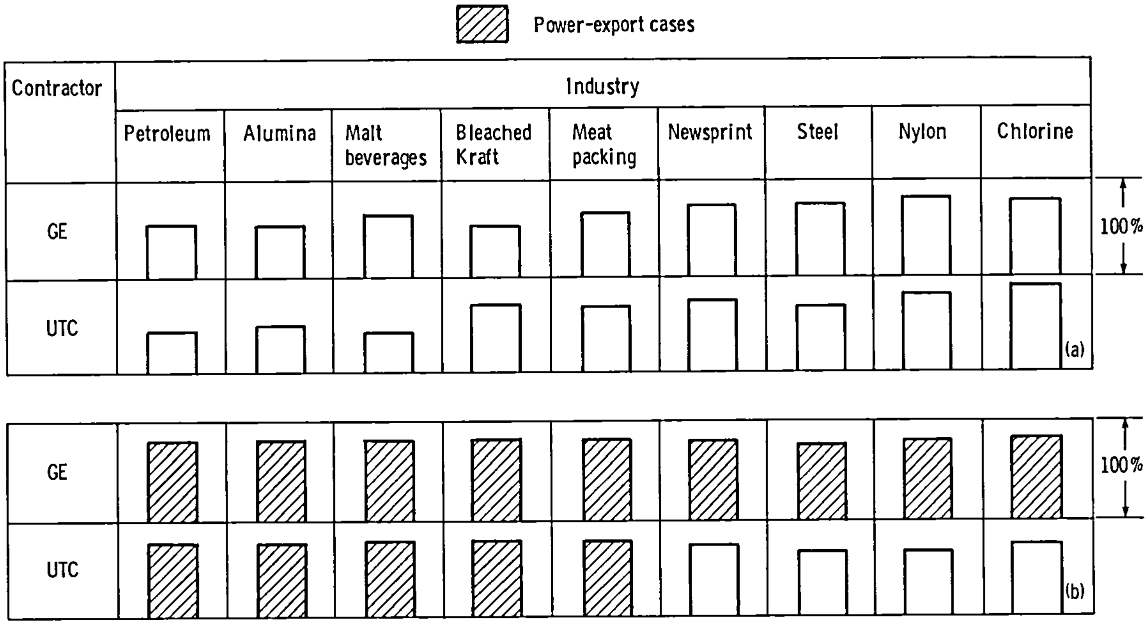
Figure 5.7-2. - Potential fuel energy saving ratios for phosphoric acid fuel cell/distillate systems.



[a] NASA modified the UTC results by deleting direct-heat requirement.

(a) No power export allowed.
(b) Power export allowed.

Figure 5.7-3. - Fuel energy saving ratios for phosphoric acid fuel cell/distillate systems.



(a) No power export allowed.
(b) Power export allowed.

Figure 5. 7-4. - Emissions saving ratios for phosphoric acid fuel cell/distillate systems.

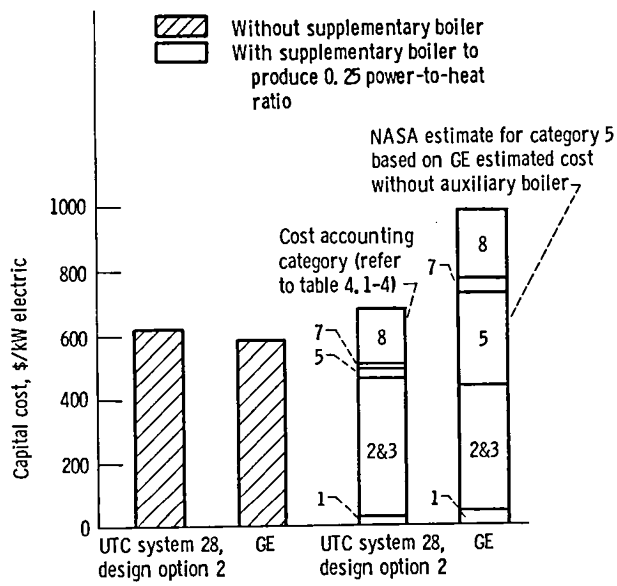


Figure 5.7-5. - Capital costs for phosphoric acid fuel cell systems. Electricity generated, 10 MW; process steam temperature, 300° F.

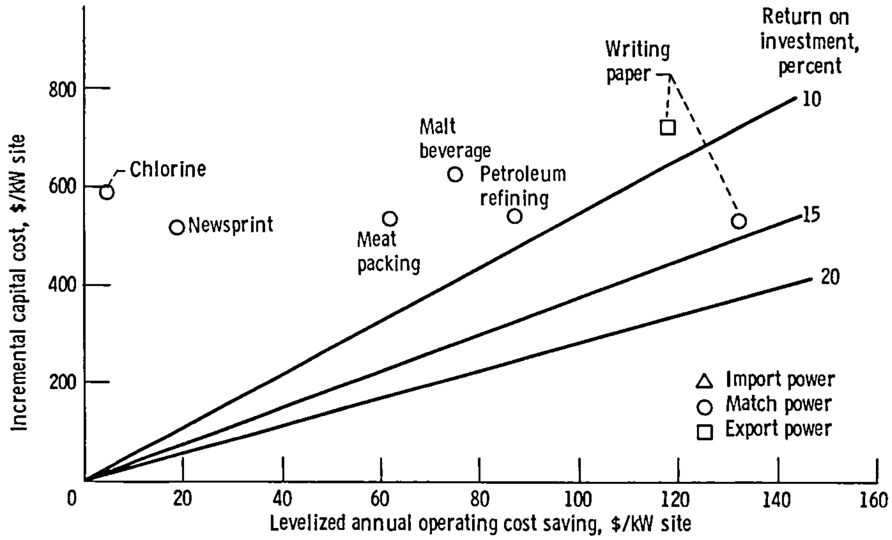
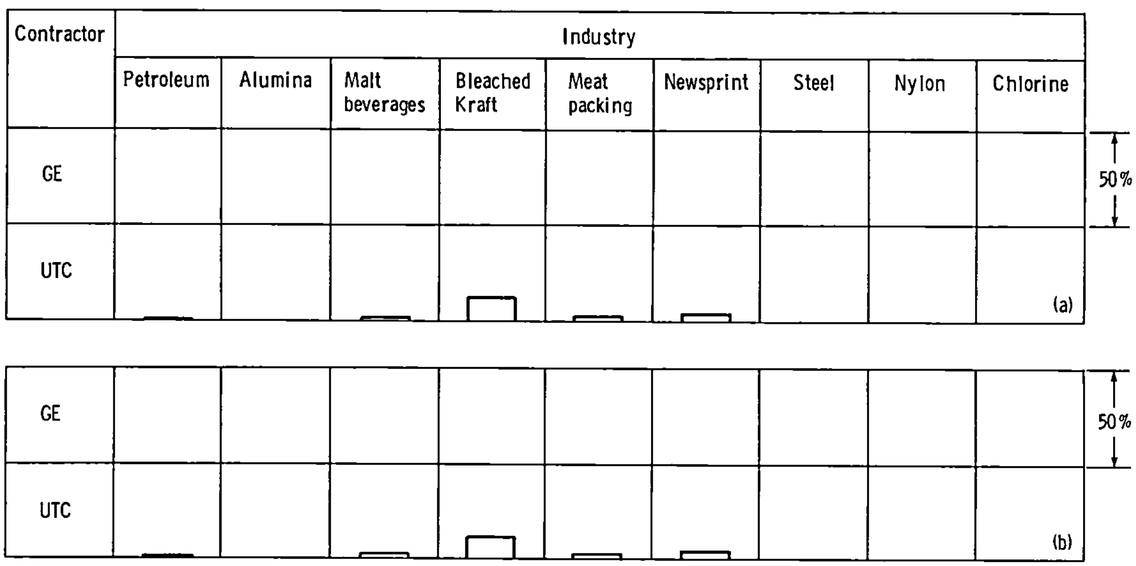


Figure 5.7-6. - Incremental capital cost as a function of levelized annual operating cost saving for UTC's phosphoric acid fuel cell/distillate system.



(a) No power export allowed.
(b) Power export allowed.

Figure 5.7-7. - Levelized annual energy cost saving ratios for phosphoric acid fuel cell/distillate systems. (Blanks denote all negative values.)

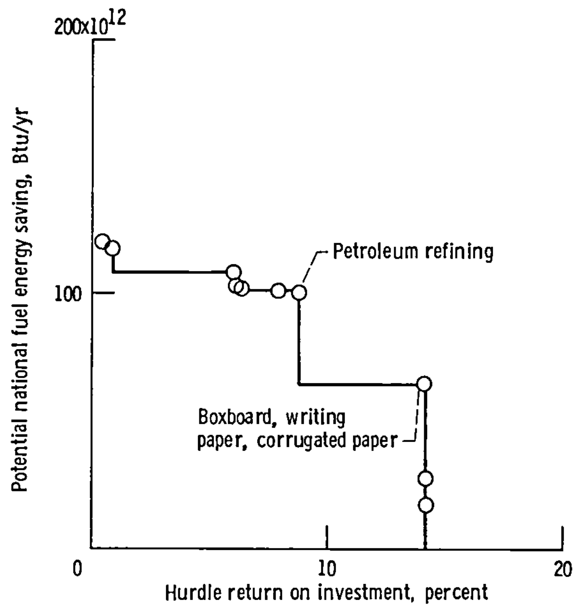


Figure 5.7-8. - Potential national fuel energy saving as a function of hurdle return on investment for UTC's phosphoric acid fuel cell/distillate system.

5.8 MOLTEN CARBONATE FUEL CELL SYSTEMS

Yung K. Choo and Raymond K. Burns

5.8.1 Configurations and Parameters

The major parameters and configurations of the molten carbonate fuel cell (MCFC) power systems studied by each contractor are summarized in table 5.8-1. Both contractors considered systems using distillate fuel (MCFC/distillate system) and systems with an integrated coal gasifier (MCFC/coal gasifier system). An adiabatic fuel reformer was used by both contractors for the MCFC/distillate systems, and an air-blown entrained-bed gasifier was used by both contractors for the MCFC/coal gasifier system.

The configurations of the MCFC/distillate systems studied by the two contractors are shown in figure 5.8-1. Among the configurations studied by UTC, the one shown in figure 5.8-1(b) gives the most attractive results. Comparison of the configurations in parts (a) and (b) indicates two major differences between contractor approaches. First, the way of removing the fuel cell waste heat is different. The GE approach involves mixing air with the catalytic burner exhaust, which flows into the cathode. This additional air removes the waste heat from the fuel cell stack. UTC removes fuel cell waste heat by cooling a part of the anode exhaust and recirculating it to the fuel cell. Second, the source of steam for the reformer is different. This difference manifests itself in the power-to-heat ratio produced by the two configurations. In the GE system steam for the reformer is generated by cooling the hot fuel gas and the catalytic burner exhaust gas. The UTC system, however, uses a part of the anode exhaust gas, which contains a substantial amount of water vapor, for the reformer instead of steam. This approach makes all of the generated steam available. This UTC approach provides much more high-quality steam for the industrial process and gives a more attractive power-to-heat ratio for the CTAS processes, as is shown in the next section.

Schematics of the MCFC/coal gasifier systems are shown in figure 5.8-2. Several differences between the configurations studied by the contractors are evident. Different operating pressures were selected by the contractors (230 psia by GE; 600 psia by UTC). The higher pressure UTC fuel gas is used to run the compressing turbine that recirculates the anode exhaust gas. Also different methods are used to remove fuel cell waste heat. GE removes fuel cell waste heat by cooling a part of the cathode exhaust and recirculating it back to the fuel cell. UTC removes fuel cell waste heat by cooling a part of the anode exhaust and recirculating it back to the fuel cell. Another difference is in the way the heat-recovery heat exchangers are arranged. In the GE system the pressurizing gas turbine exhaust is input to an economizer. Makeup water and condensate return enter the economizer and are heated by low-quality waste heat recovered in the gas turbine exhaust. Steam is generated from this hot water in the heat-recovery heat exchangers located in the cathode recycle loop and at the exit of the gasifier. Steam can be generated in a wide temperature range with little change in the amount of heat recovered. No hot water is raised in the GE system. In the UTC system hot water and steam at 300° to 500° F are generated in separate heat exchangers. If the industrial process needs only steam, the low-quality heat in the turbine exhaust is not usable. The heat recovery factor of this system therefore depends on the thermal condition it provides for process. Also, in the UTC configuration the cathode exhaust gas is cooled before it reaches the gas turbine inlet, and no net

power is produced by the pressurizing turbocompressor. In the GE configuration the cathode exhaust gas is not cooled before it reaches the turbine inlet, and power is produced by the turbocompressor.

5.8.2 Cogeneration System Performance

5.8.2.1 Fuel Energy Saving Ratio

The ratio of power to process heat produced by the distillate-fueled systems is shown in figure 5.8-3 over a range of process steam conditions, together with the potential fuel energy saving that would be achieved if the system power-to-heat ratio matched the industrial process needs. As discussed in appendix D, if the site-required power-to-heat ratio differs from the value provided by the system, the fuel saving in most cases will be lower than indicated. The GE system shown in figure 5.8-1(a) and the UTC systems shown in figure 5.8-1(b) and designated as system 30, design option 3, are the two MCFC/distillate systems whose configurations are discussed in the previous section. UTC also considered a configuration with a fuel reformer that uses part of the steam generated from recovered waste heat. This is designated as system 29, design option 2, and is compared in figure 5.8-3 with the GE system, which uses a similar fuel reformer.

Comparison of the GE system with UTC system 30, design option 3, indicates a wide difference in the power-to-heat ratios. This is due primarily to the different approach in providing the water vapor for the fuel reformer. UTC makes all of the steam generated from recovered heat available for process use. This design approach results in somewhat lower electrical efficiency, but because of the larger amount of useful steam and the lower power-to-heat ratio, the system provides a better match with many of the industries studied than does the GE system. The other UTC configuration, which uses a part of the steam for fuel reforming (i.e., system 29, design option 2), produces a power-to-heat ratio similar to that shown by the GE configuration.

The amount of heat recovered in the GE system does not vary for a wide range of steam temperature requirements. This characteristic is shown by the nearly constant value of indicated system power-to-heat ratio. It might be expected that this configuration would be widely applicable in industry. However, the power-to-heat ratio of this GE case is higher than that required by most of the industries studied. UTC system 30, design option 3, which uses anode exhaust gas as the source of water for the fuel reformer, produces a power-to-heat ratio more in the range of most processes.

Potential fuel energy saving ratio (FESR) versus system power-to-heat ratio is shown in figure 5.8-4 for systems that include an integrated coal gasifier. As indicated in table 5.8-1, GE included configurations with and without a steam bottoming cycle. Both are shown in figure 5.8-4. The GE cases that do not include a steam bottoming cycle provide heat recovery (or power-to-heat ratio) that does not change substantially with process steam temperatures from 250° to 650° F. The reason is the series arrangement of heat-recovery heat exchangers. If the process requires only hot water, the GE case will not substantially change. With the UTC configuration, however, if the process requires no hot water, the gas turbine exhaust heat, shown in the schematic of figure 5.8-2(b) as being used to heat water, is not recovered,

and the power-to-heat ratio changes substantially. This could be improved by using a series arrangement of heat exchangers.

When a steam bottoming cycle is included, the electrical efficiency and the power-to-heat ratio are increased, as shown in figure 5.8-4. A noncondensing steam turbine with back pressure is chosen so that all process steam comes from the turbine exhaust. As the saturation steam temperature corresponding to the exhaust pressure required in the process is increased, less power is obtained from the steam turbine and the power-to-heat ratio decreases as shown. The use of a steam turbine bottoming cycle provides an option for application to industrial processes requiring higher power-to-heat ratios and results in more power export for low-power-to-heat-ratio industries.

The fuel energy saving ratio results of the MCFC system matched to the nine representative industries are shown in figure 5.8-5(a). Only matching strategies that produce no excess power for export are included. The processes are listed in ascending order of power-to-heat ratio from left to right. The characteristics of these processes are given in section 3.2. UTC results for alumina and integrated steel were modified by NASA to exclude the effect of the direct-heat requirements. The direct heat specified by UTC for the integrated-steel case is the heat that could be provided by the coking coal. The UTC alumina case requires burning a specified clean fuel for the direct heat to calcine the alumina. In its modification for the integrated-steel industry, NASA used the byproduct fuel (coke oven gas and blast furnace gas) in onsite boilers for process steam but did not use it in the pressurized fuel cells. Performance and economic results were changed as required for the NASA modification cases. UTC results for the petroleum industry were also modified by NASA to exclude the effect of the direct-heat requirement on the cogeneration results. The UTC petroleum industry case requires a significant amount of direct heat, which can be provided by any type of fuel. UTC therefore switches fuel for the direct heat from residual oil in the noncogeneration case to coal in the cogeneration case of the coal-fired fuel cell system. Without NASA modification, this fuel switching to cheaper fuel (i.e., coal) results in a substantial operating cost saving.

The distillate-fueled cases (fig. 5.8-5(a)) show the highest FESR's for the higher power-to-heat ratio processes. As shown in figure 5.8-3 the GE system configuration produces a power-to-heat ratio of about 1.8 and achieves its best fuel saving in the nylon and chlorine processes, which according to GE data require power-to-heat ratios greater than 15. UTC system 30, design option 3, produces a lower power-to-heat ratio (fig. 5.8-3) and achieves a higher fuel energy saving in those processes with power-to-heat ratio requirements in the intermediate range. Also, for the UTC configuration the fuel saving is high in the nylon and chlorine industries, which, according to UTC data, require power-to-heat ratios near unity, just slightly above that produced by their fuel cell system configuration.

Figure 5.8-5(a) also shows the FESR's for these nine processes matched with a molten carbonate fuel cell system with an integrated coal gasifier. Each contractor's system matches well with its newsprint process and achieves the highest FESR with that process. The FESR results for other industries are mainly affected by the degree of match between the power-to-heat ratio and the temperature characteristics of the system and the process.

The GE MCFC/steam turbine/coal gasifier system has (fig. 5.8-5(a)) FESR results similar to those for the GE MCFC/coal gasifier system without a steam turbine. The system with the steam turbine achieves somewhat higher FESR values for the steel, nylon, and chlorine industries because it has higher electrical efficiency and a better matching power-to-heat ratio with the three industries.

The FESR results when power export is allowed are shown in figure 5.8-5(b). Cases where power can be exported are crosshatched. The FESR values are improved in many cases where using a larger power system and making excess power results in a greater amount of heat recovery for process use. The excess power exported is accounted for in the FESR calculation. Comparing figures 5.8-5(a) and (b) shows that extent of the improvement is greater for the processes with lower required power-to-heat ratios. The lower the site-required power-to-heat ratio as compared with that produced by the energy conversion system, the greater the amount of excess power produced in the match-heat strategy. This will affect the economic results, as illustrated in later figures and parametrically in appendix D.

5.8.2.2 Emissions Saving Ratio

The emissions saving ratio (EMSR) performance is shown in figure 5.8-6. The emissions shown correspond to the sum of NO_x, SO_x, and particulates. The EMSR values are closely proportional to the FESR values because higher FESR means less fuel input to the system. Comparison of figures 5.8-6(a) and (b) indicates that the EMSR results improve in several industries when power export is allowed. The reasons are that FESR results were improved in those industries with power export and that emissions from the fuel cell systems are less than those from the coal-fired utilities.

Table 5.8-2 shows the values of the emissions per unit of fuel consumption used by the contractors for the energy conversion systems. UTC selected a regenerable metal oxide for sulfur removal from the fuel gas upstream of the fuel cell. The sulfur dioxide is then released on site when the metal oxide is regenerated. GE selected a disposable zinc oxide sulfur removal system. Thus GE's site emissions of sulfur dioxide are much lower than UTC's. For the coal-derived distillate the NO_x emissions level of the GE system is close to the complete oxidization level of the fuel-bound nitrogen and is substantially higher than that of the UTC system. Apparently UTC assumed some removal of the fuel-bound nitrogen.

5.8.2.3 Capital Cost

Capital cost estimates for the 10-MW-electric molten carbonate fuel cell systems with recovery of waste heat as 300° F steam are shown in figure 5.8-7. Each contractor estimated the costs according to the cost accounts described in section 4.1. The bar graphs in figure 5.8-7(a) include all costs of equipment and installation for a 10-MW-electric fuel cell system including all fuel-handling, storage, and processing equipment and all heat recovery equipment. Costs of a supplementary boiler and its associated fuel-handling equipment are not included.

Figure 5.8-3 shows that the distillate-fueled systems studied by GE and UTC produce significantly different power-to-heat ratios. If they were both

applied to a process with low power-to-heat ratio, using a match-power strategy, they would require different sizes of supplementary boilers. Figure 5.8-7(b) shows the cost estimates required for a supplementary boiler sized to yield a power-to-heat ratio of 0.25, which is near the mean value for all processes studied in CTAS (fig. 3.2-2). This substantially changes the capital cost comparisons. The effect of site power-to-heat ratio relative to that produced by the system and the effect of the matching strategy used on incremental capital cost are discussed in appendix D. Aside from differences in the size and hence cost of a supplementary boiler, the largest difference between the cost estimates of GE and UTC is in the balance-of-plant category.

The capital cost estimates of the MCFC systems with an integrated gasifier (fig. 5.8-7(a)) are substantially higher than the estimates for the MCFC/distillate systems mainly because of the higher category 2 cost, which includes the coal gasifier. The ratio of the capital cost estimates (both contractors) for the MCFC/coal gasifier systems is smaller than the ratio for the distillate systems, which is about 2, as shown in figure 5.8-7(a).

The capital costs ($/kW electric) for GE's systems with and without a steam turbine are about the same because the additional power generated by the steam turbine compensates for the capital cost increase for the steam bottoming cycle.

5.8.2.4 Economics

The incremental capital cost versus levelized operating cost saving of the MCFC systems is shown in figures 5.8-8 to 5.8-10 for the nine representative industries. These figures also show lines corresponding to constant return on investment (ROI) values. The origins correspond to the noncogeneration situation, where required electricity is purchased and onsite steam is produced in a residual-fueled boiler. Since the power requirements of the processes vary considerably (section 3.2), the incremental capital cost and levelized operating cost saving are expressed per unit of site power required. Not all of the cogeneration cases are sized to match the site power requirement.

None of the GE cases using distillate fuel yield a levelized annual operating cost saving. Therefore only UTC results appear in figure 5.8-8. GE specified that supplementary boilers use the same type of fuel as used by the energy conversion system. UTC designated that supplementary boilers use residual fuel. Thus the operating costs of GE distillate-fueled cogeneration cases are higher than UTC's because of the higher supplementary boiler fuel price. In addition, for these fuel cell systems GE's estimates of O&M costs are significantly higher than UTC's. In some cases there is an operating cost saving in terms of fuel and electricity costs alone, but when O&M is included, cogeneration operating costs are higher than the noncogeneration operating costs. GE estimates are higher for maintenance, labor, and materials (because of the replacement cost of the disposable zinc oxide). UTC assumed the use of a regenerable sulfur cleanup system. Comparing figure 5.8-9 with 5.8-8 indicates that the incremental capital cost of the system with the integrated gasifier is much higher, but because of the lower price of coal as compared with distillate fuel, the operating cost saving is also higher. The contractors' assumptions concerning the fuel used in the supplementary boiler in match-power cases affect the comparison of contractor results in figure 5.8-9. UTC assumed that the supplementary boiler uses residual fuel, and GE assumed

that the gasifier is sized large enough to provide enough fuel gas for the supplementary boiler in addition to the fuel cell power system. Because of this effect, GE's match-power cases tend to have higher operating cost savings. When power export is allowed, both capital costs and operating cost savings are increased.

The effect of using cheaper coal rather than distillate fuel is shown in those cases involving power export. More cases had positive operating cost savings and hence are shown in figure 5.8-9 but did not appear in figure 5.8-8.

The economic results of the GE MCFC/steam turbine/coal gasifier system are about the same as those for the GE system without the steam turbine. The results are shown in figure 5.8-10.

The other economic parameter used in CTAS to combine the effects of capital and operating cost is the percent savings in levelized annual energy cost (LAECSR). The best LAECSR results are presented in figure 5.8-11. The GE MCFC/distillate system has negative LAECSR's for all nine representative industries. This results from the operating costs of the cogeneration cases being higher than the noncogeneration operating cost for the reasons discussed above. The UTC MCFC/distillate system shows low LAECSR's in most industries because of the use of expensive distillate oil.

The MCFC/coal gasifier systems show high LAECSR's in several industries. The LAECSR reaches higher values for the coal-fired systems than for the distillate-fueled systems because of the larger operating cost saving derived from using a less expensive fuel. This occurs in spite of the higher capital costs. GE's high LAECSR's in the petroleum and alumina industries (in spite of only moderate fuel energy savings, fig. 5.8-5) are due mainly to the replacement of the expensive noncogeneration system onsite boiler fuel (residual) by cheaper fuel (coal) in the cogeneration system.

In some cases (e.g., meat packing and malt beverage) figure 5.8-5 indicates appreciable fuel energy savings, but figure 5.8-11 indicates no levelized annual energy cost savings. As shown in figure 5.8-9, there were operating cost savings for cogeneration in these processes, but because of a combination of small powerplant size and less than full-time operation in these processes, the incremental capital cost is high as compared with the operating cost saving. In terms of LAECSR the increased capital cost outweighs the operating cost saving. The GE MCFC/steam turbine/coal gasifier shows LAECSR's similar to those for the system without the steam turbine.

Inclusion of the power-export cases does not improve the LAECSR's much as shown in figure 5.8-11(b). The positive effect on LAECSR of the high FESR values with power export is compensated for by the negative effect of the capital cost increase for larger systems. The results shown in figures 5.8-8 to 5.8-10 generally agree with those in figure 5.8-11 concerning processes that yield the most attractive results for each type of molten carbonate fuel cell system. The UTC results in figures 5.8-8 and 5.8-9(b) indicate that the distillate-fueled systems, because they require less capital, reach higher values of ROI than the gasifier systems. However, figure 5.8-11 indicates that the gasifier cases, because they burn cheaper fuel, yield higher values of LAECSR's than the distillate-fueled systems. Comparisons based on LAECSR's sometimes indicate different conclusions than those based on ROI calculated relative to noncogeneration.

5.8.2.5 Relative National-Basis Fuel Saving

Plots of energy saving aggregated to a national basis as a function of hurdle ROI are shown in figures 5.8-12 and 5.8-13. The procedure used to evaluate these curves is described in section 4.4. It was assumed that each system will be 100 percent implemented in new-capacity additions or retirement replacements between 1985 and 1990 in each process where the results yield an ROI greater than the hurdle rate. Only processes specifically studied by each contractor were considered. These figures are intended to illustrate the comparative potential saving versus ROI requirement, but they are not an illustration of the absolute magnitude of the savings. Only the results for non-power-export cases are shown in the figures. When power-export cases are included, energy savings for the MCFC/coal gasifier systems improve because of the increase in FESR. However, ROI values drop slightly because of the increased capital costs of the larger systems used for power export.

Note that the maximum ROI achieved in any of the processes studied, as shown in figures 5.8-12 and 5.8-13, is substantially the same as that shown in figures 5.8-8 to 5.8-10 for the subset of nine processes.

No results are shown for the GE MCFC/distillate system because no positive ROI's are achieved. Figure 5.8-12 shows results for the UTC MCFC/distillate system when the system electric power is matched with the site power. The results indicate that with a hurdle ROI rate of 10 percent a significant national fuel saving will be achievable.

Results for the MCFC/coal gasifier systems are shown in figure 5.8-13. The GE results (fig. 5.8-13(a)) include some import cases since GE did not consider match-power strategy if that strategy produced more heat than required by the process. The level of potential national fuel saving is lower than that for the UTC distillate-fueled system because of the generally lower FESR results for the gasifier cases. Results for both contractors' systems indicate that the potential national energy saving for a hurdle ROI rate of 10 percent is less than one-third of that if no hurdle rate is considered.

5.8.3 <u>Summary</u>

The range of results achieved by the molten carbonate fuel cell systems for the nine representative industries is presented in table 5.8-3. The fuel energy saving ratio (FESR) results are attractive in many industries, and they depend mainly on the degree of the system match with the industries. Both GE and UTC systems achieve FESR values above 30 percent for well-matching industries. Industries with low power-to-heat ratios show low FESR's, but their FESR's increase if power export is considered.

The distillate-fueled molten carbonate fuel cell (MCFC/distillate) systems have low levelized annual energy cost saving ratios (LAECSR). The GE system has negative LAECSR for all nine representative industries because of the relatively high operation and maintenance (O&M) cost estimates and the use of relatively expensive distillate fuel.

Both contractors' systems with the integrated gasifier show attractively high LAECSR's in the writing paper, newsprint, and chlorine industries. GE coal-fired systems also show high LAECSR's in the petroleum and alumina

industries because of the fuel type assumed for the supplementary boiler. Power export does not improve the LAECSR's for the MCFC/distillate systems. Coal-fueled systems show some improved LAECSR's with power export.

The MCFC systems achieve very high emissions saving ratios (EMSR) because of the fuel savings achieved and the fuel processing and cleanup system that is required by the fuel cell. Differences between the contractors' estimates of SO_x emissions at the site follow from an assumption of the use of a regenerable metal oxide cleanup by UTC with release of SO_x on site and the use of a disposable zinc oxide system by GE. This difference also significantly affects the comparison of O&M cost estimates and hence economic results.

None of the GE distillate-fueled cases show an operating cost saving, even though there are savings in terms of fuel and electricity costs, because of the estimated high O&M costs of the fuel cell system. Thus none of the GE distillate-fueled cases show LAEC savings or positive ROI's. Some of UTC's cases do, however, yield attractive ROI's. Coal-fired systems yield lower ROI's as a result of the higher capital cost associated with coal handling, cleaning, and gasification. The LAECSR's reach higher values for the systems with an integrated coal gasifier than for the distillate-fueled systems. The reason is that the coal-fueled cases achieve larger operating cost savings by using a less expensive fuel in spite of the higher capital costs.

In section 4.4 a screening process is described that was used by NASA to identify the most attractive systems for the nine representative processes discussed previously. The cogeneration results of each system matched with these nine processes were considered in terms of all of the parameters used in CTAS. A number of industries using the UTC distillate-fueled molten carbonate fuel cell system survived this screening process. These industries are among those that are mentioned as attractive in table 5.8-3. Industries mentioned as attractive in table 5.8-3 using both the GE and UTC integrated-gasifier molten carbonate systems also passed the screening process (table 5.8-3).

The coal-fueled systems have the potential for further improvement in performance and economic results if the supplementary boiler uses as much byproduct fuel as available from the process and if the gasifier is sized to provide fuel gas for the molten carbonate fuel cell power system and to provide any additional fuel gas for the supplementary boiler. UTC assumed that the supplementary boiler uses a residual fuel and that the gasifier is sized only for the needs of the energy conversion system. GE on the other hand assumed that the gasifier is sized large enough to provide all of the fuel gas required by the energy conversion system and the supplementary boiler. GE did not use any byproduct fuel in the gasifier or the supplementary boiler.

TABLE 5.8-1. - ENERGY CONVERSION SYSTEM PARAMETERS AND CONFIGURATIONS STUDIED FOR MOLTEN CARBONATE FUEL CELL SYSTEMS

Parameter	General Electric Co.	United Technologies Corp.
Petroleum- and coal-derived distillate-fueled systems		
Cell stack temperature, °F	1000-1300	1100-1300
Cell stack pressure, psia	150	120
Cell stack temperature-control configuration	Excess cathode air	Anode recycle
Fuel processing	Adiabatic reformer uses steam	Adiabatic reformer uses anode exhaust for system 30, design option 3 Uses steam in other designs
Fuel cleanup	Disposable ZnO	Regenerable metal oxides
Coal-fired systems		
Cell stack temperature, °F	1000-1300	1100-1300
Cell stack pressure, psia	150	150
Cell stack temperature-control configuration	Cathode recycle	Anode recycle
Gasifier	Air-blown entrained bed (230 psia/ 2475 °F	Air-blown entrained bed (600 psia, 2400 °F
Bottoming cycle	With and without steam turbine	Without steam turbine

TABLE 5.8-2. - EMISSIONS FOR MOLTEN CARBONATE FUEL CELL SYSTEMS

Pollutant	Fuel					
	Petroleum-derived distillate		Coal-derived distillate		Coal (integrated gasifier)	
	GE	UTC	GE	UTC	GE	UTC
	Emissions, $lb/10^6$ Btu					
Oxides of sulfur	0.003	0.510	0.003	0.570	0.001	0.070
Oxides of nitrogen	.110	.083	1.510	.087	.001	.201
Particulates	0	0	.030	.034	.005	0

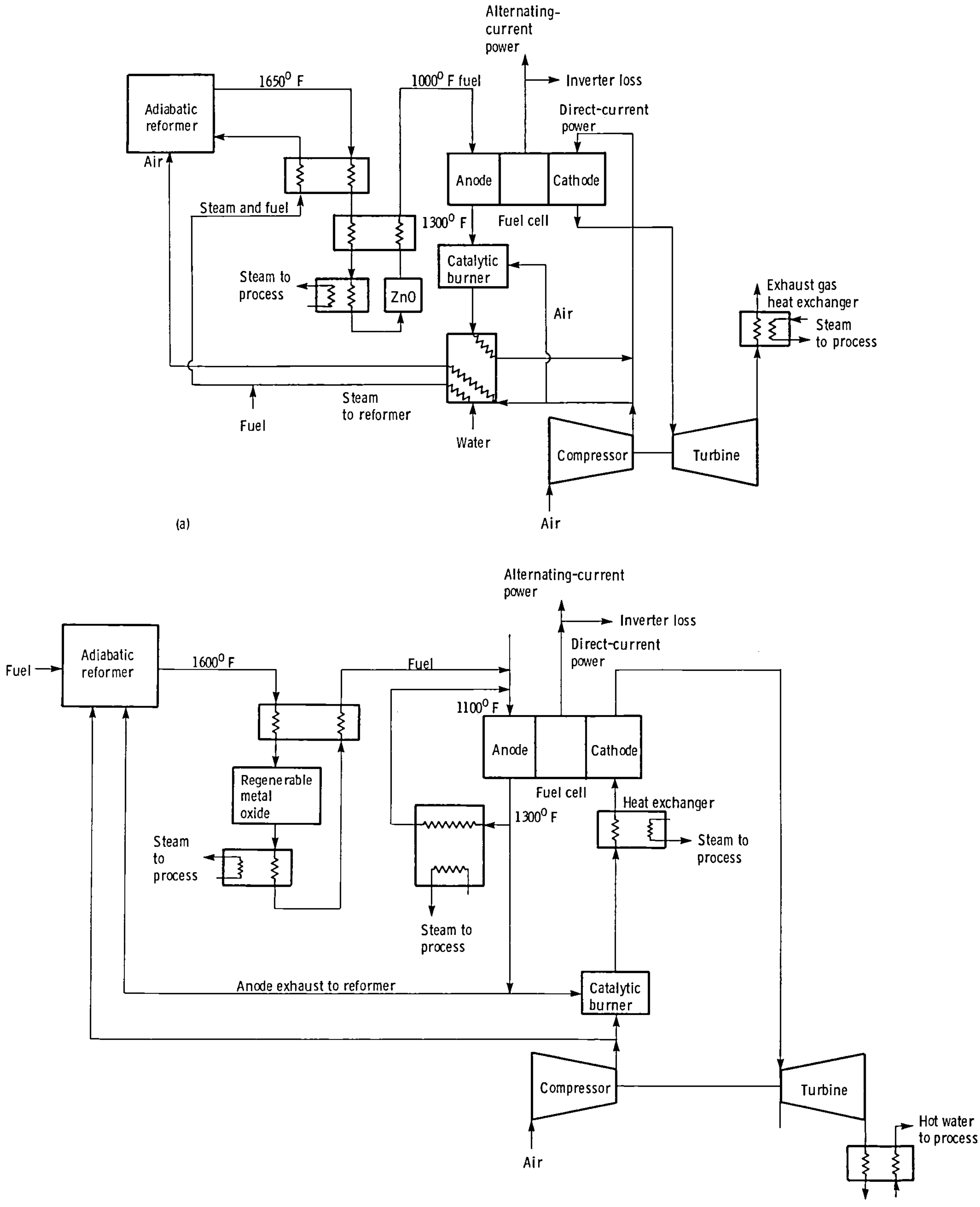
TABLE 5.8-3. - RANGE OF RESULTS FOR MOLTEN CARBONATE FUEL CELL SYSTEMS USED WITH THE NINE REPRESENTATIVE INDUSTRIES

(a) No power export allowed

Energy conversion system subgroup	Contractor	Fuel energy saving ratio, FESR	Industry with maximum FESR	Emissions saving ratio, EMSR	Industry with maximum EMSR	Levelized annual energy cost, LAEC	Industry with maximum LAEC	Return on investment, ROI, percent	Industry with maximum ROI
Molten carbonate fuel cell distillate	GE	10-35	Nylon chlorine	All negative	-----	42-52	Writing paper	0	--------
	UTC	6-36	Nylon	Negative to 15	Chlorine	9-79	Chlorine	1-20	Writing paper
Molten carbonate fuel cell integrated gasifier	GE	Negative to 32	Newsprint	Negative to 25	Petroleum	26-90+	Newsprint	1-16	Petroleum
	UTC	3-39	Newsprint	Negative to 30	Newsprint	10-91		4-13	Newsprint; chlorine
Molten carbonate fuel cell/	GE	Negative to 34	Newsprint	Negative to 26	Petroleum	23-83	Newsprint	0-17	Petroleum

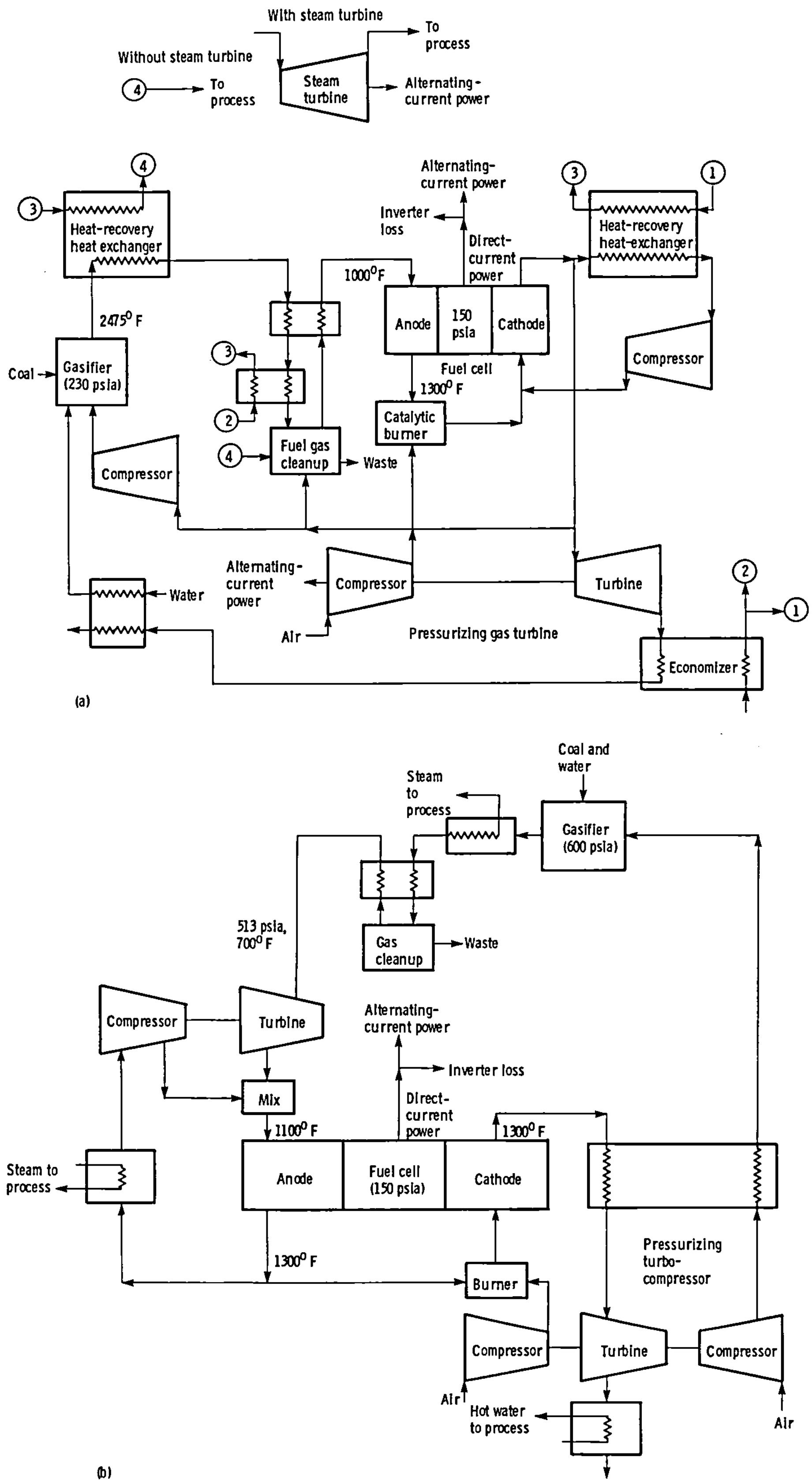
(b) Power export allowed

Energy conversion system subgroup	Contractor	Fuel energy saving ratio, FESR	Industry with maximum FESR	Emissions saving ratio, EMSR	Industry with maximum EMSR	Levelized annual energy cost, LAEC	Industry with maximum LAEC	Return on investment, ROI, percent	Industry with maximum ROI
Molten carbonate fuel cell/ distillate	GE	10-36	Chlorine; Nylon, writing paper	All negative	--------	42-52	Writing paper	0	----------
	UTC	6-42	Meat packing, chlorine	Negative to 15	Chlorine	9-79	Chlorine	0-20	Writing paper
Molten carbonate fuel cell/ intregrated gasifier	GE	Negative to 34	Petroleum; newsprint	Negative to 33	Petroleum	26-100-	Petroleum; writing paper; newsprint	0-16	Petroleum
	UTC	3-39	Newsprint	Negative to 30	Newsprint	10-91	Newsprint	4-13	Newsprint; chlorine
Molten carbonate fuel cell/ steam turbine/integrated gasifier	GE	Negative to 39	Newsprint	Negative to 42	Petroleum	23-100-	Petroleum; writing paper; newsprint	0-17	Petroleum



(a) GE.
(b) UTC (system 30, design option 3).

Figure 5.8-1. - Schematics of molten carbonate fuel cell/distillate systems.



(a) GE (with and without steam bottoming cycle).
(b) UTC (without steam bottoming cycle).

Figure 5.8-2. - Schematics of molten carbonate fuel cell / integrated gasifier systems.

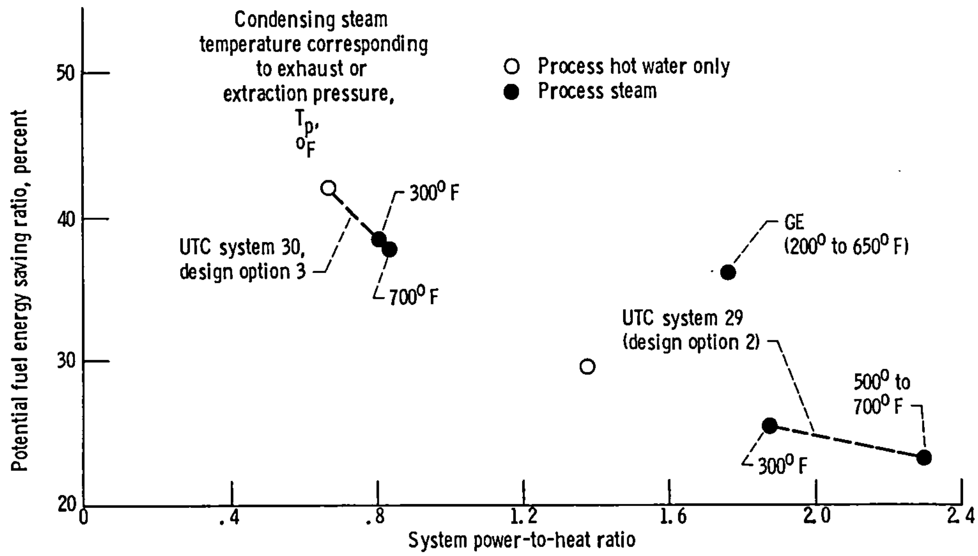


Figure 5.8-3. - Potential fuel energy saving ratios for molten-carbonate fuel cell/distillate systems.

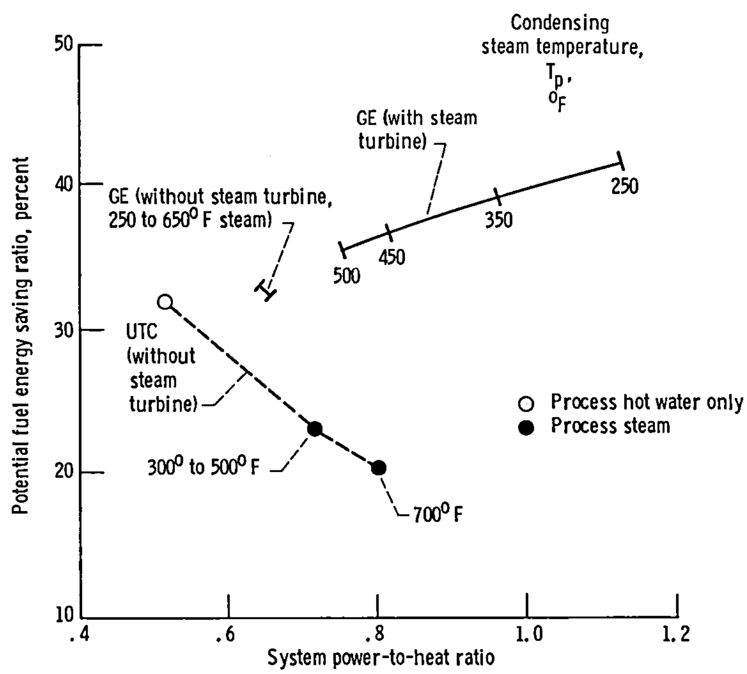
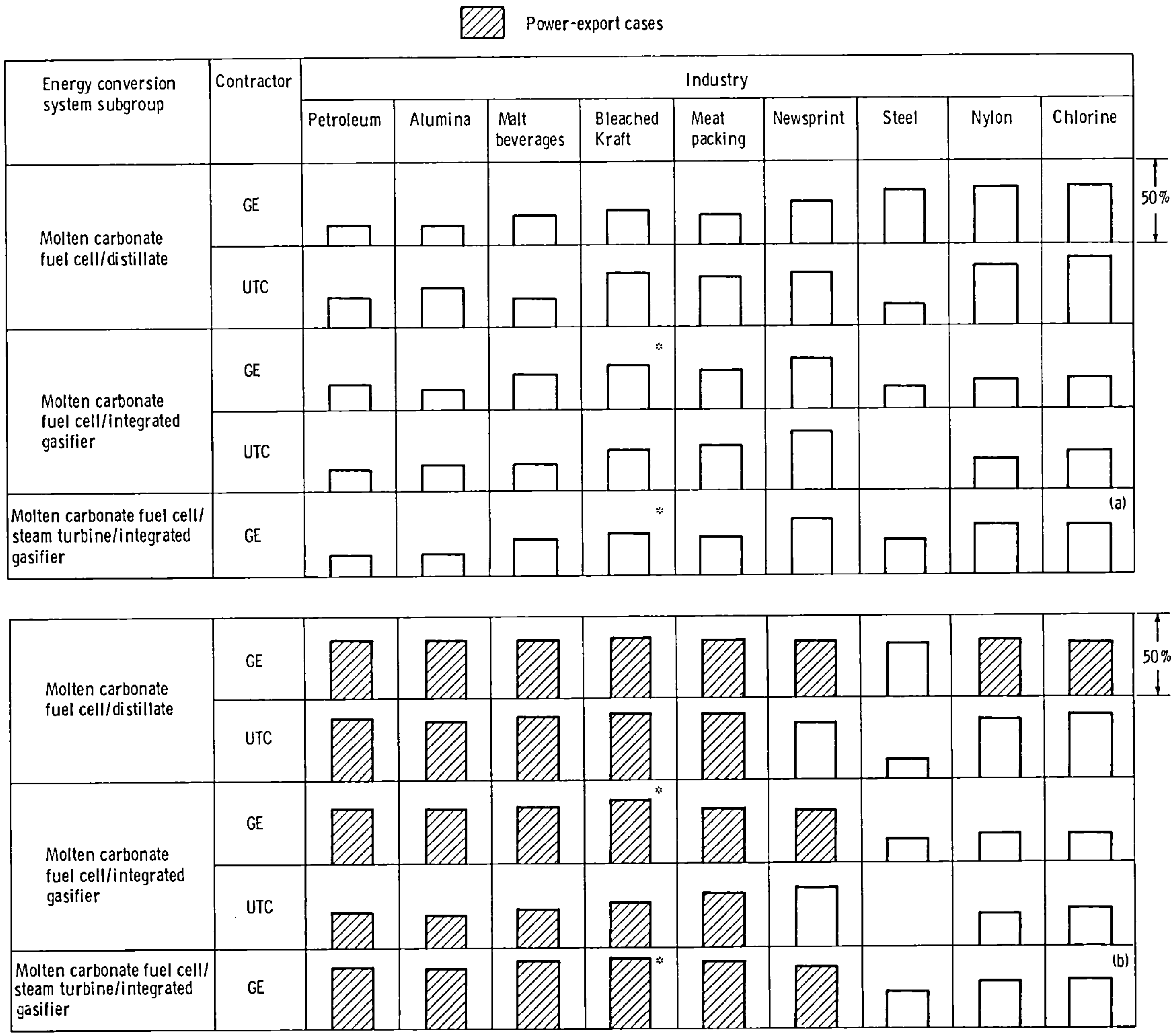


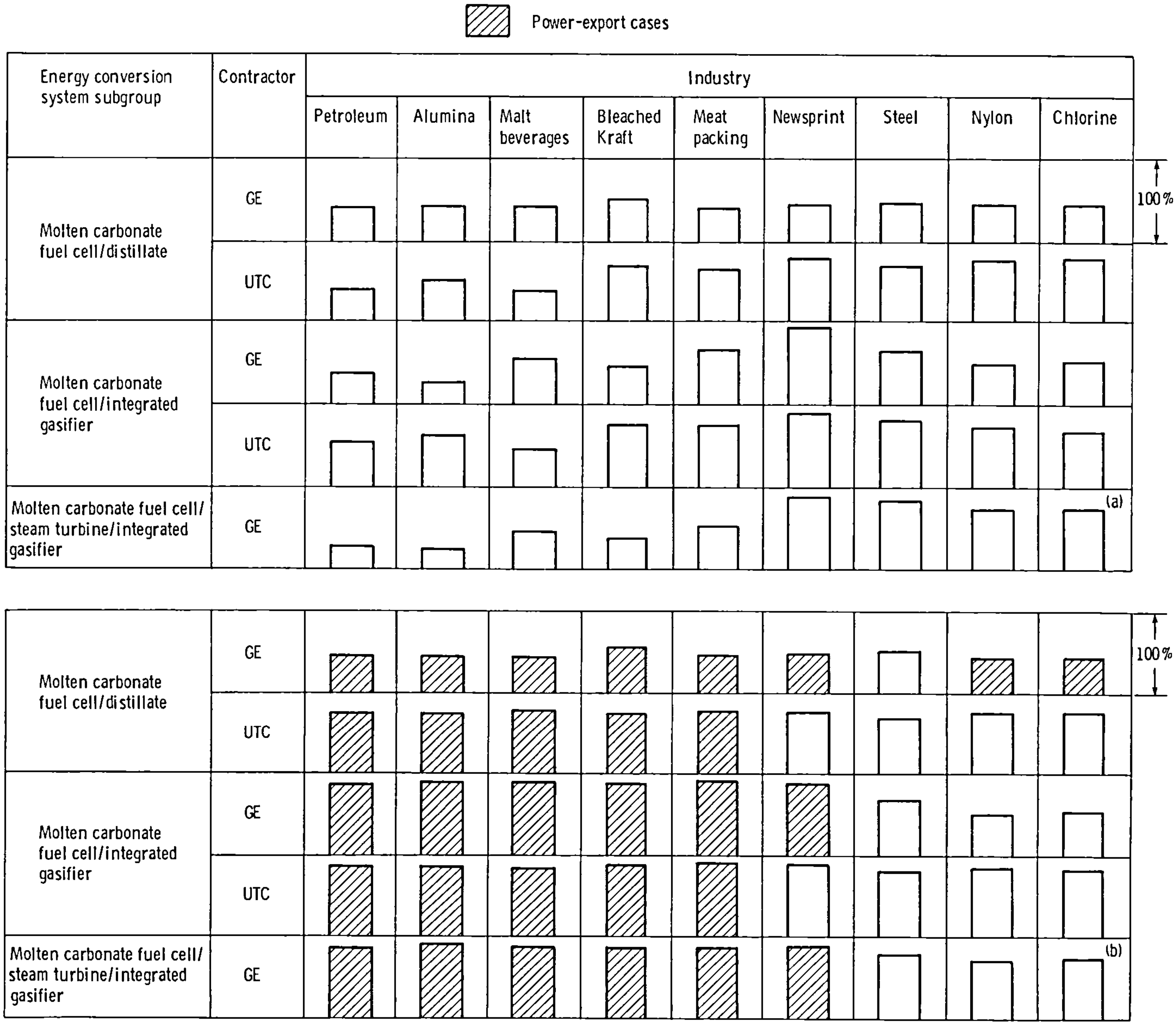
Figure 5.8-4. - Potential fuel energy saving ratios for molten-carbonate fuel cell/integrated gasifier system.



* Modified by NASA to include use of byproduct fuel in cogeneration supplementary boiler.

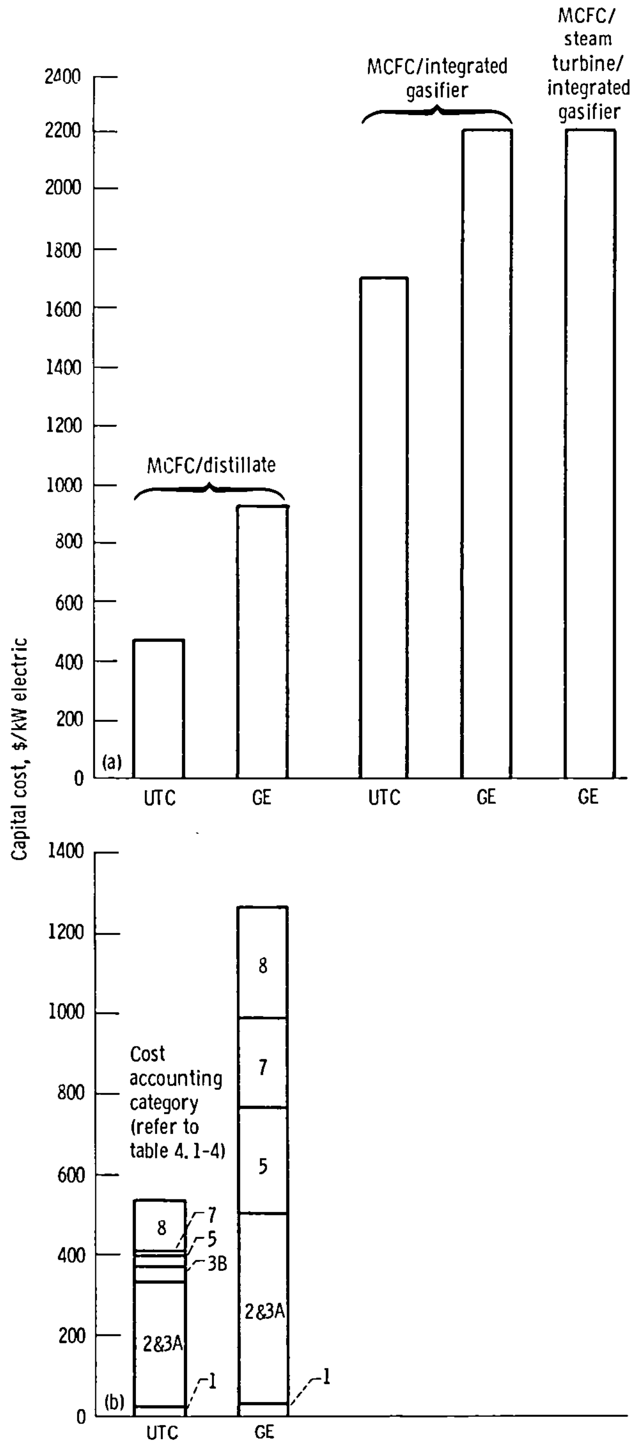
(a) No power export allowed.
(b) Power export allowed.

Figure 5.8-5. - Fuel energy saving ratios for molten carbonate fuel cell systems. (Blanks denote all negative values.)



(a) No power export allowed.
(b) Power export allowed.

Figure 5.8-6. - Emissions saving ratios for molten carbonate fuel cell systems.



(a) Without supplementary boiler. MCFC distillate system.
(b) With supplementary boiler to produce 0.25 power-to-heat ratio.

Figure 5.8-7. - Capital costs for molten carbonate fuel cell systems.

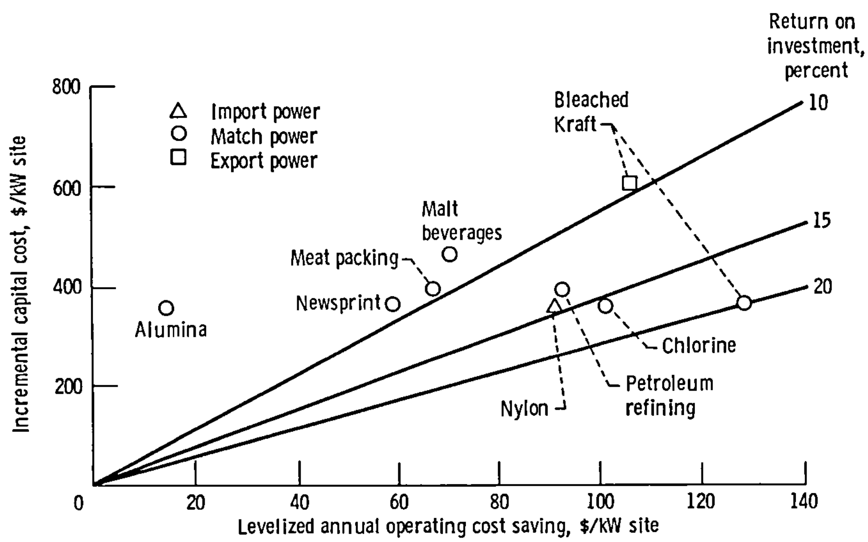
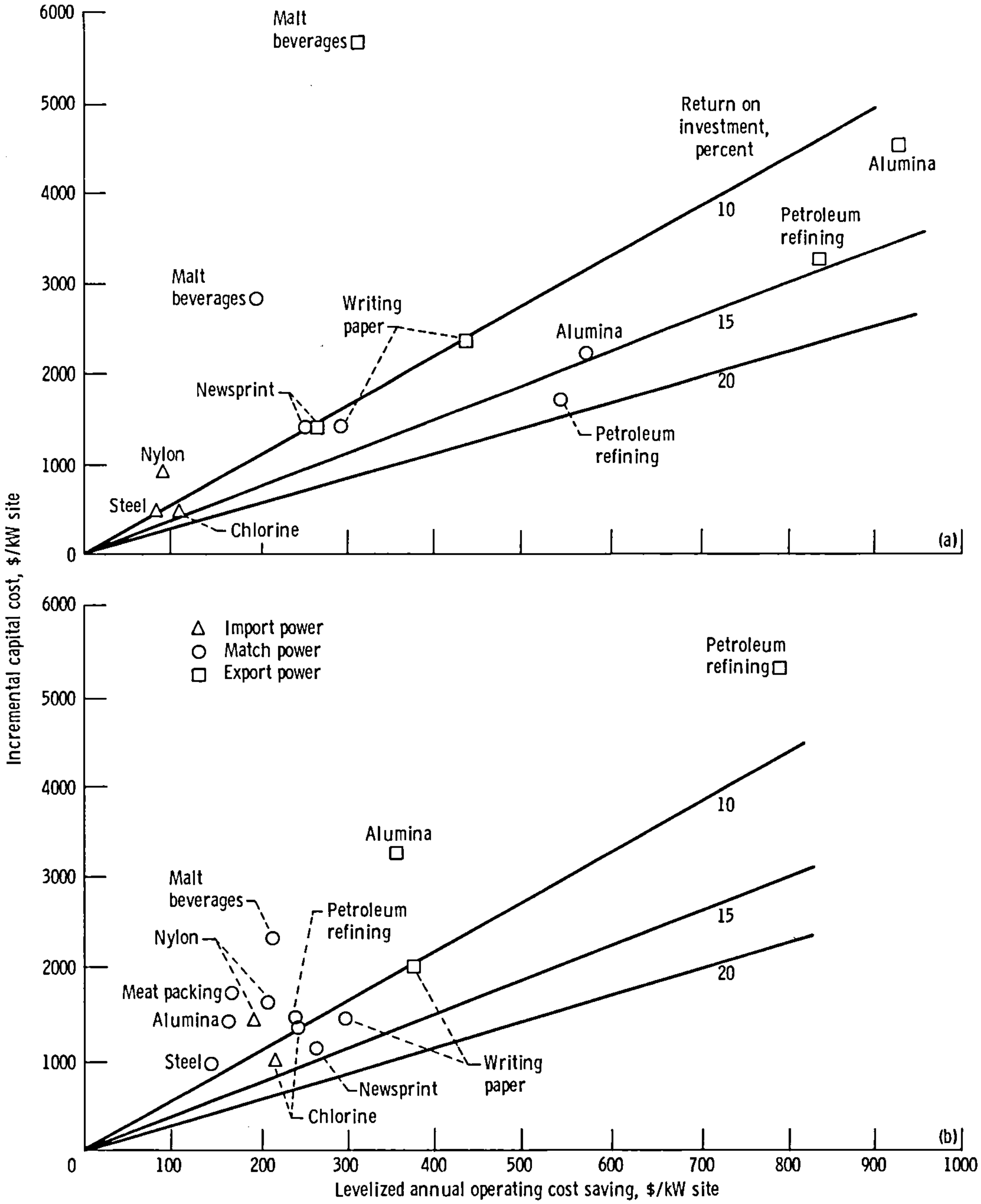


Figure 5.8-8. - Incremental capital cost as a function of levelized annual operating cost saving for UTC's molten carbonate fuel cell/distillate system. (All GE results have negative operating cost savings.)



(a) GE.
(b) UTC.

Figure 5.8-9. - Incremental capital cost as a function of levelized annual operating cost saving for molten carbonate fuel cell/integrated gasifier systems.

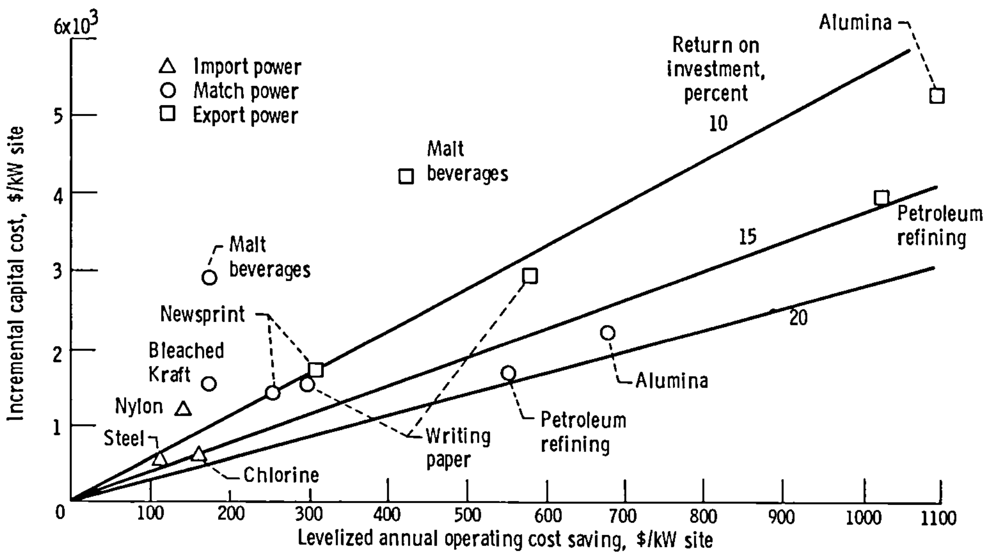
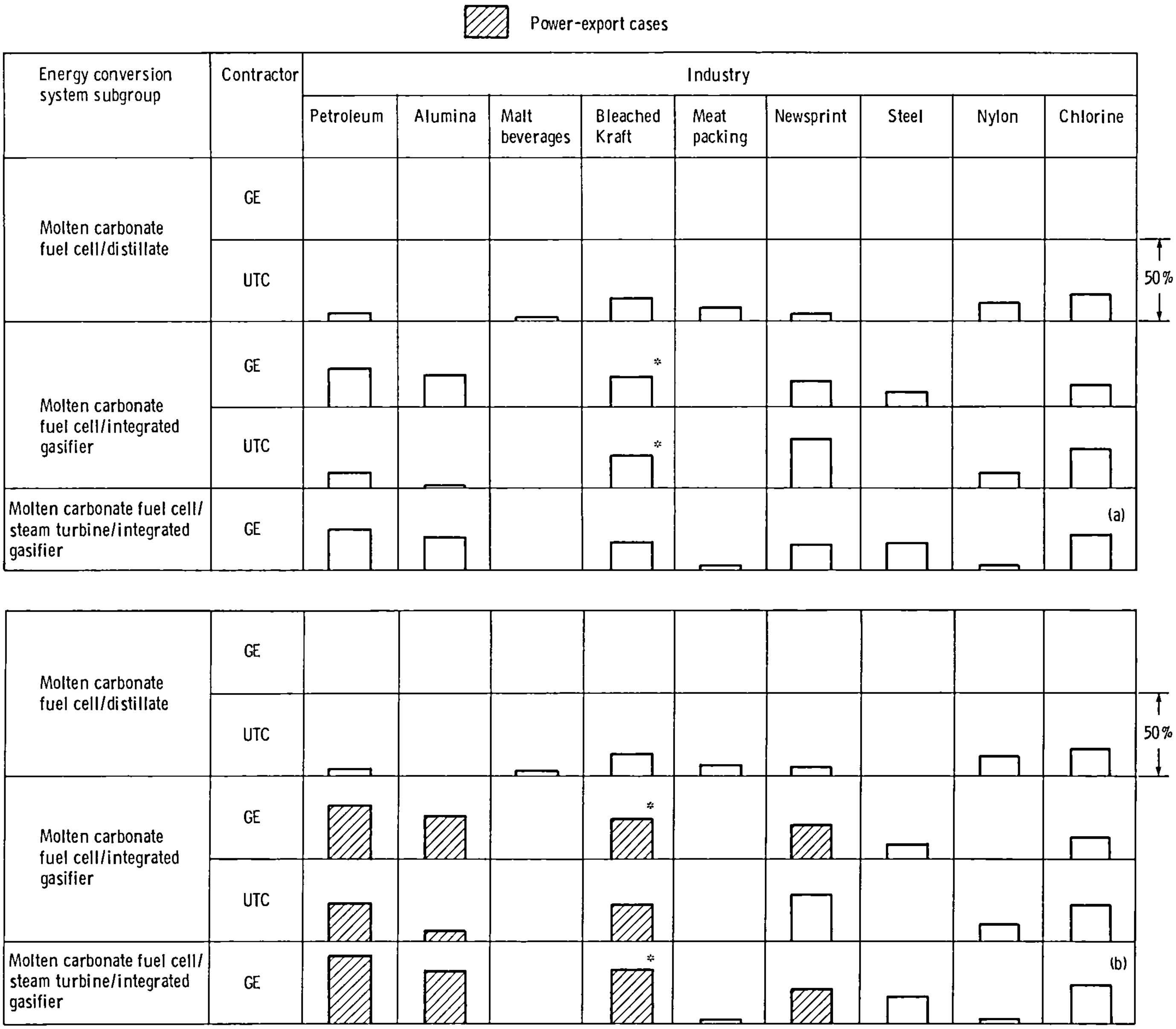


Figure 5.8-10. - Incremental capital cost as a function of levelized annual operating cost saving for GE's molten carbonate fuel cell/steam turbine/integrated gasifier system.



*Modified by NASA to include use of byproduct fuel in cogeneration supplementary boiler.

(a) No power export allowed.
(b) Power export allowed.

Figure 5.8-11. - Levelized annual energy cost saving ratios for molten carbonate fuel cell systems. (Blanks denote all negative values.)

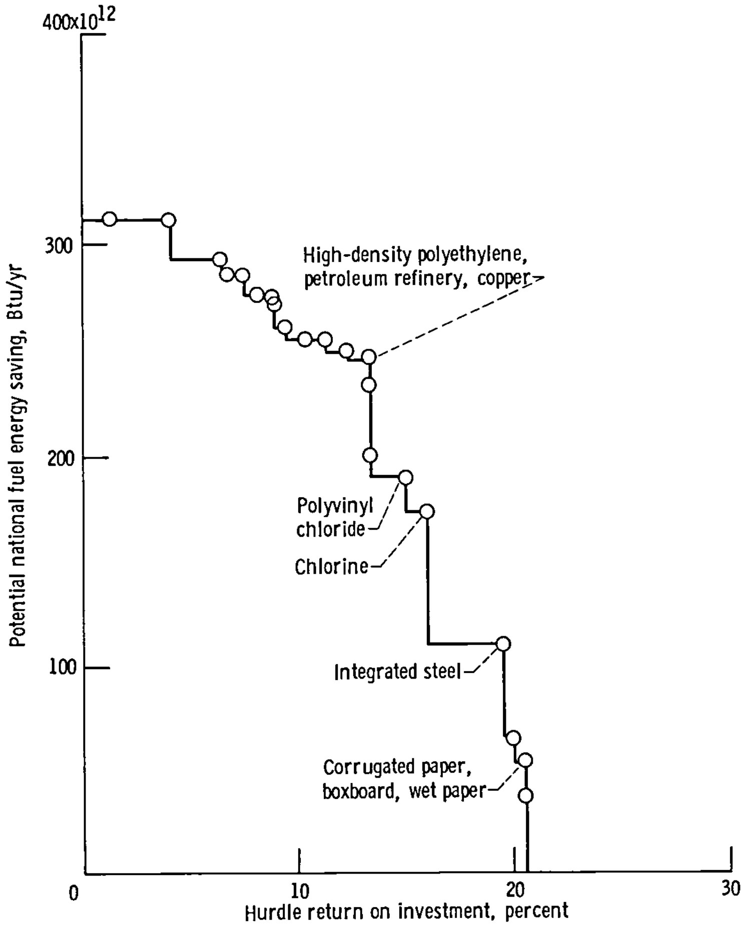
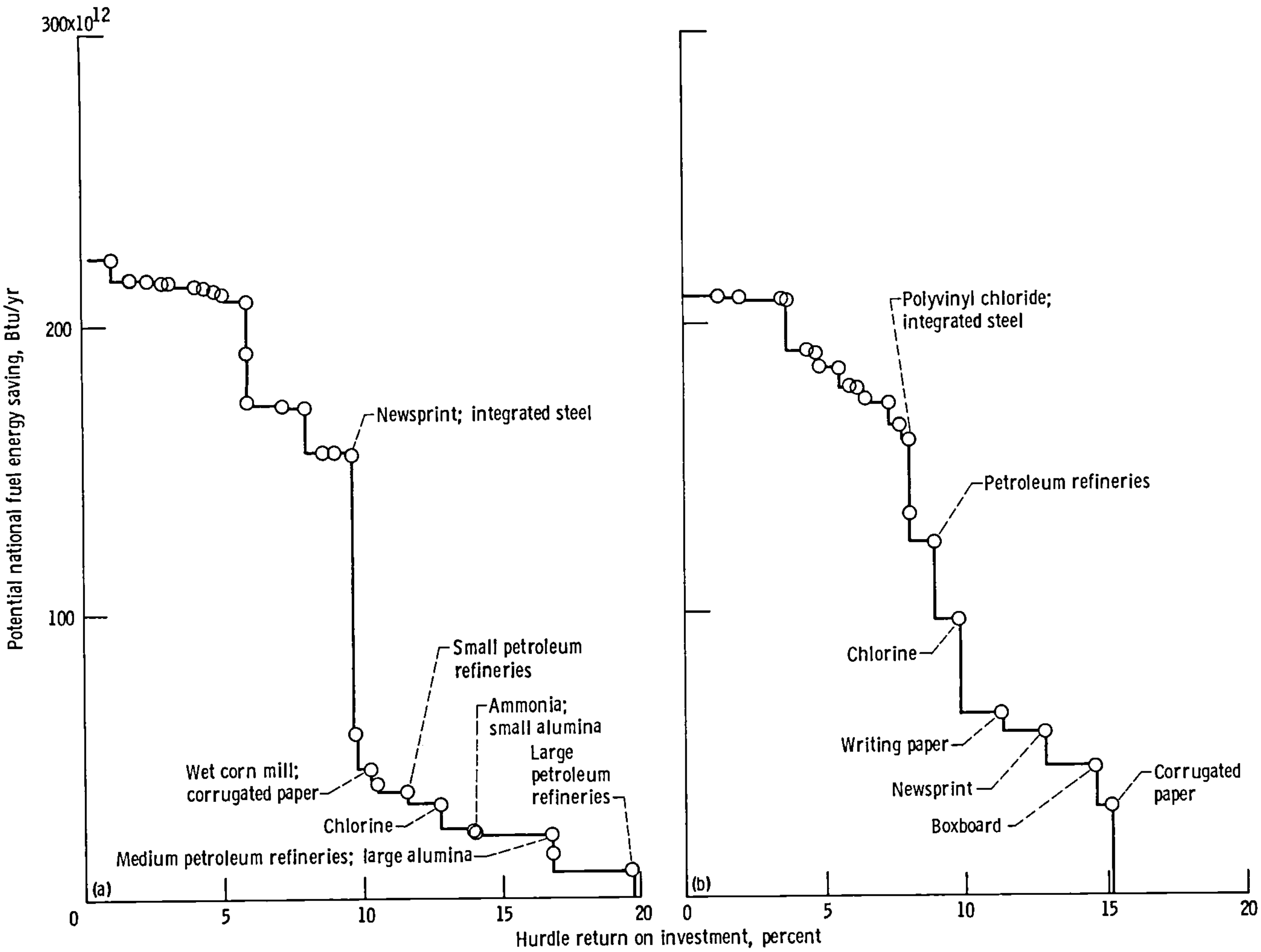


Figure 5. 8-12. - Potential national fuel energy saving as a function of hurdle return on investment for UTC's molten carbonate fuel cell/distillate system. (Match power.)



(a) GE (no export).
(b) UTC (match power).

Figure 5.8-13. - Potential national fuel energy saving as a function of hurdle return on investment for molten carbonate fuel cell/integrated coal gasifier systems.

5.9 THERMIONIC POWER SYSTEMS

Yung K. Choo

5.9.1 Configurations and Parameters

The major parameters and configurations studied by each contractor are described in table 5.9-1. Both contractors studied thermionic power systems with and without a steam bottoming cycle using residual fuel. In addition, General Electric studied coal-fired power systems with flue gas desulfurization (FGD).

The configurations of the thermionic power systems considered by the contractors are shown in figure 5.9-1. Comparison of the parameters and configurations indicates differences in converter arrangement, supply of heat to the emitters, cooling of the collectors, operating temperatures of emitters and collectors, and secondary air preheat temperatures. Effects of major differences on performance and cost are discussed in the next section. The GE system (fig. 5.9-1(a)) preheats the combustion air to 1000° F by using the waste heat from collectors. The United Technologies systems (fig. 5.9-1(b) and (c)) preheat the combustion air by using the waste heat in the combustion gas in the high- and low-temperature air preheaters. Two air-preheat temperatures (2200° F in the ceramic heat exchanger and 1400° F in the metal heat exchanger) were considered.

The GE design (fig. 5.9-1(a)) uses high-temperature thermionic converters installed in the wall of the radiant section of the furnace. These converters are followed by low-temperature thermionic converters located between the radiant and superheater furnace zones. The emitters are directly heated by radiation and convection. A part of the heat supplied to the emitters is converted into direct-current power, and the rest is rejected to incoming combustion air. A large fraction of the heat rejected to the air is further transmitted to steam. GE used the same system configurations and parameters for both coal-fired and residual-fueled systems.

The UTC designs (figs. 5.9-1(b) and (c)) transfer part of the combustion heat to the thermionic emitters through heat pipes. For a fixed emitter temperature of 2400° F two collector temperatures are used. A temperature of 1113° F is used when steam is raised for the steam turbine, and 763° F is used when the thermionic power system does not have any steam bottoming cycle.

An alternative configuration considered by NASA to see what the performance potential of the thermionic power system would be when waste heat in the form of hot gas and air was directly used in the process is shown in figure 5.9-2. In this configuration hot combustion product leaving the furnace at 2300° F and collector cooling air at 700° F were directly used in a hypothetical process. Performance and conditions of the thermionic topping system are based on the results described in reference 1.

5.9.2 Cogeneration System Performance

5.9.2.1 Fuel Energy Saving Ratio

The ratios of power to process heat produced by the systems for the steam conditions indicated are shown in figure 5.9-3, together with the fuel energy

saving that would be achieved if the energy conversion system power-to-heat ratio matched the process needs. If the site-required power-to-heat ratio differs from the value provided by the system, as shown in this figure, the fuel savings in most cases will be lower than indicated here. The GE results in the figure represent the performance of both oil-fired and coal-fired power systems since GE assumed the same system configurations and parameters including furnace performance. UTC considered only residual-fueled thermionic power systems.

The performance potential of thermionic power systems that do not have any steam turbines is shown in figure 5.9-3(a). By achieving a higher system electrical efficiency, the UTC system with the high air preheat temperature achieves slightly higher fuel energy saving ratio (FESR) and power-to-heat ratio than the system using a lower air preheat temperature. The GE thermionic system with a 1000° F air preheat temperature shows performance results similar to those of the UTC system with a 1400° F air preheat temperature.

The performance of the contractors' thermionic systems with a steam turbine bottoming cycles is shown in figure 5.9-3(b). Performance is scattered in a wide area on the FESR-versus-power-to-heat-ratio plane. The performance difference between the GE and UTC systems is due to the different steam turbine types. The GE power system achieves higher FESR values through greater waste heat recovery by using a back-pressure steam turbine. The performance results of the UTC thermionics/steam turbine systems reflect the low heat recovery factors associated with the extraction condensing turbines. Performance of the UTC thermionics/steam turbine systems is represented by three points that refer to the three design options described in table 5.9-1. The significant performance differences among the three UTC design options are due to the differences in steam extraction pressure and extraction rate. Design options 2 and 3 preheat the combustion air to 1400° F. Design option 1 uses a ceramic air preheater for 2200° F combustion air. Design option 3 achieves the highest FESR of the three options by extracting a large fraction of throttle steam flow (80 percent) for industrial process at a relatively low extraction pressure of 65 psia. As the extraction pressure is raised from 65 psia in design option 3 to 615 psia in design option 2 for the same extraction rate of 80 percent, the FESR and the power-to-heat ratio are decreased.

The power-to-heat ratio performance difference between design options 1 and 2 is caused by changes in the heat recovery associated with the different steam extraction rates and the electrical efficiency associated with the air preheat. The FESR values are about the same because the positive effect of the high air preheat is compensated for by the negative effect of the low heat recovery factor.

The power-to-heat ratio produced by the thermionic power system that supplies hot gas for direct heat is shown in figure 5.9-4, together with the potential FESR that could be achieved if the system power-to-heat ratio matched the process needs as in the NASA case (fig. 5.9-2). This system is able to provide hot gas at a high temperature if the combustion products from the thermionic boiler are compatible with the process direct-heat requirement.

Fuel energy saving ratio results for the thermionic power systems matched to the nine representative industries are shown in figure 5.9-5. The processes are listed in ascending order of power-to-heat ratio from left to right. UTC results for the petroleum, alumina, and integrated-steel industries were modified by NASA to exclude the effects of the direct-heat requirements on the

cogeneration results. The direct heat specified by UTC for the integrated-steel process represents coking coal to produce coke for the blast furnace. The UTC alumina process requires burning a specified clean gaseous fuel to support the calcination of the alumina. The direct heat required by the UTC petroleum process does not require any specified fuel.

In the petroleum industry therefore UTC switched fuel from residual fuel in the noncogeneration system to coal in the thermionic cogeneration systems. Changing from an expensive fuel to cheaper coal resulted in a higher operating cost saving. When modifying the UTC integrated-steel process, NASA used byproduct fuel in the thermionic furnaces.

The FESR results when no power export is allowed are shown in figure 5.9-5(a). The GE thermionic power system with a steam bottoming cycle achieves higher FESR values than the UTC system because the GE system with the back-pressure steam turbine has a higher performance than the UTC system with an extraction condensing turbine. The GE system with the steam bottoming cycle shows higher FESR results than the system without a steam bottoming cycle in all nine industry applications because of its higher performance potential (fig. 5.9-3). High FESR values were achieved by the UTC thermionic systems for the integrated-steel industry because the large amount of byproduct fuel available in the UTC process is used in the thermionic boiler and the supplementary boiler. Figure 5.9-5(b) shows FESR results when power export is included. The FESR values are improved in many cases where using a larger power system and making excess power for export results in a greater amount of heat recovery for process use. The excess power exported is accounted for in the FESR calculation. Comparing figures 5.9-5(a) and (b) indicates that the extent of the improvement is greater for the process with the lower required power-to-heat ratio. The lower the site power-to-heat ratio as compared with that produced by the system, the greater the amount of excess power produced in the match-heat strategy. This will affect the economic results.

5.9.2.2 Emissions Saving Ratio

The emissions saving ratio (EMSR) results for the nine representative industries are shown in figure 5.9-6. The results shown correspond to the sum of NO_x, SO_x, and particulate emissions. The EMSR values are closely related to the FESR values because higher FESR means less fuel input to the system.

The emissions per unit of fuel consumption used by the contractors for the energy conversion systems are shown in table 5.9-2. The residual-fuel systems show lower SO_x and NO_x emissions than the coal-fired systems. The residual-fuel thermionic power systems achieve higher EMSR results than the GE coal-fired systems, as shown in figure 5.9-6.

Comparison of the EMSR results in figures 5.9-6(a) and (b) indicates that the EMSR results improve in several industries when power export is allowed. For the residual-fuel systems the reasons are that the FESR results are better in those industries with power export and that emissions from the residual-fuel thermionic systems are less than those from the coal-fired utilities. The GE coal-fired system without a steam bottoming cycle does not have better EMSR results with power export. The GE coal-fired system with the steam bottoming cycle shows some increase in EMSR mainly because of the substantial FESR improvement with power export.

5.9.2.3 Capital Cost

Capital cost estimates for the 10-MW-electric thermionic power systems with recovery of system waste heat as 300° F steam are compared in figure 5.9-7. The figure includes all costs of equipment and installation, including all fuel-handling, storage, and processing equipment and all heat recovery equipment. Costs of any supplementary boiler and its associated fuel-handling equipment are not included.

The estimated capital costs of the contractors' residual-fueled thermionic power systems have the highest capital cost in dollars per kilowatt electric of all the residual-fueled CTAS energy conversion systems. GE's cost estimates are significantly higher than UTC's estimates. The GE capital cost estimate for the residual-fueled thermionic system without any steam bottoming cycle is more than three times the UTC cost estimate. There are significant differences between the two contractors' cost estimates in the heat source and energy conversion system cost categories. The GE cost estimate for the residual-fueled thermionic/steam turbine system is about two times higher than the UTC cost estimate.

The estimated capital costs for the GE coal-fired thermionic systems are higher than those for the residual-fueled thermionic systems. The unit capital cost of the coal-fired thermionic/steam turbine system is about 60 percent of the coal-fired system cost without any steam turbine.

The high estimated capital costs greatly affect the economic results of the thermionic power systems. They are pointed out in the next section, where return on investment (ROI) and levelized annual energy cost saving ratio (LAECSR) are discussed.

5.9.2.4 Economics

Incremental capital cost versus levelized operating cost saving is shown in figures 5.9-8 to 5.9-10 for the thermionic systems matched to the nine representative industries. Lines of constant ROI values are shown. The origin corresponds to the noncogeneration situation, where required electricity is purchased and onsite steam is produced in a residual-fueled boiler. Since the power requirements of the processes vary considerably (table 4.4-1), the incremental capital cost and levelized operating cost saving are expressed per unit of site power required.

The results for the UTC thermionics/heat-recovery steam generator (HRSG) power system using residual fuel are shown in figure 5.9-8. GE systems yield either negative or small positive operating cost savings and therefore do not appear in the figure. Even the GE systems with positive annual operating cost savings show negligible ROI values because of the high incremental capital cost estimates together with the small operating cost savings.

The ROI values achieved by the UTC system are about 10 percent or higher in the chlorine, steel, and newsprint industries, as shown in the figure, when the match-heat strategy is used and power is imported from the utility to satisfy site power requirements. Those cases do not achieve large operating cost savings, but they require lower incremental capital costs and result in ROI values of 10 percent or higher. In the match-power strategy, excess heat

is produced by the system because those processes require larger power-to-heat ratios than the ratio of about 0.25 provided by the UTC thermionics/HRSG system.

Results for residual-fueled thermionics/steam turbine power systems are shown in figure 5.9-9. The ROI results for the UTC system (fig.5.9-9(b)) are lower than the results for the UTC thermionics/HRSG system (fig. 5.9-8). The operating cost saving achieved by the system with the steam turbine cycle is larger, but the capital cost increase for the bottoming cycle has a more negative effect on the ROI results. The GE results show lower ROI values than the UTC results. Comparing the results for the newsprint and writing paper industries indicates that the GE thermionics/steam turbine system achieves a larger operating cost saving, but requires a higher incremental capital cost.

Results for the GE coal-fired thermionic power systems are shown in figure 5.9-10. UTC did not consider coal-fired thermionic power systems. Parts (a) and (b) of the figure present the results of the thermionics/HRSG system and the thermionics/steam turbine system, respectively. The coal-fired systems achieve substantially higher operating cost savings than the residual-fueled systems (fig. 5.9-9) by using the cheaper coal. But they require higher capital costs than the residual-fueled systems. The combined effect results in ROI values of about 10 percent or lower. The system with the steam bottoming cycle shows slightly higher ROI values than the system without the bottoming cycle.

The other economic parameter used in CTAS to combine the effects of capital and operating cost is the percent savings in levelized annual energy cost (LAECSR) (section 4.3). The LAECSR results are presented in figure 5.9-11. High capital costs and moderate FESR values are reasons for the low or negative LAECSR's with and without power export.

All GE cases using residual-fueled thermionic systems result in negative LAECSR's because of the high capital and operation and maintenance (O&M) cost estimates. The UTC residual-fueled thermionics/HRSG system shows small LAECSR's for several industries by combining low incremental capital cost with an operating cost saving. Those UTC cases that show positive LAECSR's correspond to the cases with the relatively high ROI values shown in figure 5.9-8. The highest LAECSR, for the steel industry, is the result modified by NASA in which byproduct fuel was used in the supplementary boiler. The UTC thermionics/steam turbine system shows even lower LAECSR's than the system without the steam turbine because the effect of the capital cost increase is greater than the effect of the operating cost saving increase.

Positive LAECSR's were achieved by the GE coal-fired systems in the petroleum and alumina industries. Savings are due to changing from residual fuel for the noncogeneration onsite boiler to the cheaper coal for the cogeneration supplementary boiler. GE used the same fuel for the energy conversion system and the onsite supplementary boiler, which is used for additional process steam that cannot be provided by the conversion system. Using coal in the conversion system did not improve the LAECSR's for other industries because the GE coal-fired thermionics systems have substantially higher capital cost estimates.

5.9.2.5 Relative National-Basis Fuel Saving

National energy saving as a function of hurdle ROI is shown in figures 5.9-12 to 5.9-15. The procedure used to evaluate these curves is described in section 4.4. It was assumed that each system will be 100 percent implemented in new-capacity additions or as retirement replacements between 1985 and 1990 in each process where the results yield an ROI greater than the hurdle rate shown. These figures are intended to illustrate the comparative potential-saving-versus-ROI requirement. They do not illustrate the absolute magnitude of savings.

National energy saving versus ROI for the UTC residual-fueled thermionics/HRSG power system in the CTAS industries is shown in figure 5.9-12. This system cannot achieve ROI's greater than 10 percent for match-power cases (fig. 5.9-12(a)). The results of the maximum-FESR strategy include import-power cases and show that both ROI and national energy saving results are improved (fig. 5.9-12(b)). Yet the power system achieves 15 percent ROI only in the chlorine industry with power import; in all other CTAS industries, ROI's are less than 10 percent. A large energy saving in the petroleum industry (fig. 5.9-12(b)) is associated with a large power export. This case, however, occurs at a low ROI of 3 percent.

The results for the UTC residual-fueled thermionics/steam turbine system for the match-power strategy are shown in figure 5.9-13. All ROI values are less than 10 percent. For this UTC power system the maximum-FESR strategy results have even smaller ROI results and therefore are not shown. Results for the GE residual-fueled systems are not shown because they have very low ROI's in all CTAS industries.

Results for two GE coal-fired systems are shown in figures 5.9-14 and 5.9-15. The energy saving by the coal-fired thermionics/HRSG system is very small at ROI's greater than 10 percent. The coal-fired thermionics/steam turbine/coal system shows higher ROI's and higher national energy savings than the power system without a steam turbine. Inclusion of power-export cases does not result in positive ROI's.

5.9.3 Summary

The range of results achieved by the thermionic power systems for the nine representative industries are presented in table 5.9-3. The fuel energy saving ratios (FESR) range from low to moderate, but the economic results in terms of the levelized annual energy cost saving ratio (LAECSR) and the return on investment (ROI) are low because of the high capital costs and low operating cost savings estimated by the contractors. The upper values of the FESR and emissions saving ratio (EMSR) ranges are increased when power-export cases are included (table 5.9-3(b)). But no improvement in the ROI and LAECSR occurs because the capital cost increase of the large power system for power export overcompensates for the effect of the FESR increase on the economic results.

The UTC oil-fired power systems show better economic results than the GE oil-fired power systems mainly because the estimated capital and operation and maintenance costs are lower. The GE coal-fired power systems achieve slightly better economic results than their oil-fired power systems mainly because cheaper fuel (coal) is used.

TABLE 5.9-1. - ENERGY CONVERSION SYSTEM PARAMETERS AND CONFIGURATIONS STUDIED FOR THERMIONIC POWER SYSTEMS

Parameter	General Electric Co.	United Technologies Corp.
Emitter temperature, °F	[a]2420; [b]1880	2400
Air preheat temperature, °F	1000	[c]2200; [d]1400
Thermionic/residual systems		
Collector temperature, °F	[a]710; [b]900	763
Thermionic/steam turbine/residual systems		
Collector temperature, °F	[a]710; [b]900	1113
Steam turbine:		
Type	Back pressure	Extraction condensing
Throttle, psia/°F	1465/1000	1815/1050
Back pressure	Process steam pressure	-------------
Extraction pressure, psia	--------------	[e]615; [f]65
Extraction rate, percent	--------------	[c]50; [d]80
Thermionic/coal (FGD) systems		
Collector temperature, °F	[a]710; [b]900	-------------
Thermionic/steam turbine/coal (FGD) systems		
Collector temperature, °F	[a]710; [b]900	-------------
Steam turbine:		
Type	Back pressure	-------------
Throttle conditions, psia/°F	1465/1000	-------------
Back pressure	Process steam temperature	-------------

[a]High-temperature thermionic energy conversion.
[b]Low-temperature thermionic energy conversion.
[c]Design option 1.
[d]Design options 2 and 3.
[e]Design options 1 and 2.
[f]Design option 3.

TABLE 5.9-2. - EMISSIONS FOR THERMIONIC POWER SYSTEMS

Pollutant	Fuel			
	Coal-derived residual		Coal (FGD)	
	GE	UTC	GE	UTC
Oxides of sulfur	0.8	0.824	1.2	---
Oxides of nitrogen	.5	.5	.7	---
Particulates	.1	.1	.1	---
Total	1.4	1.424	2.0	---

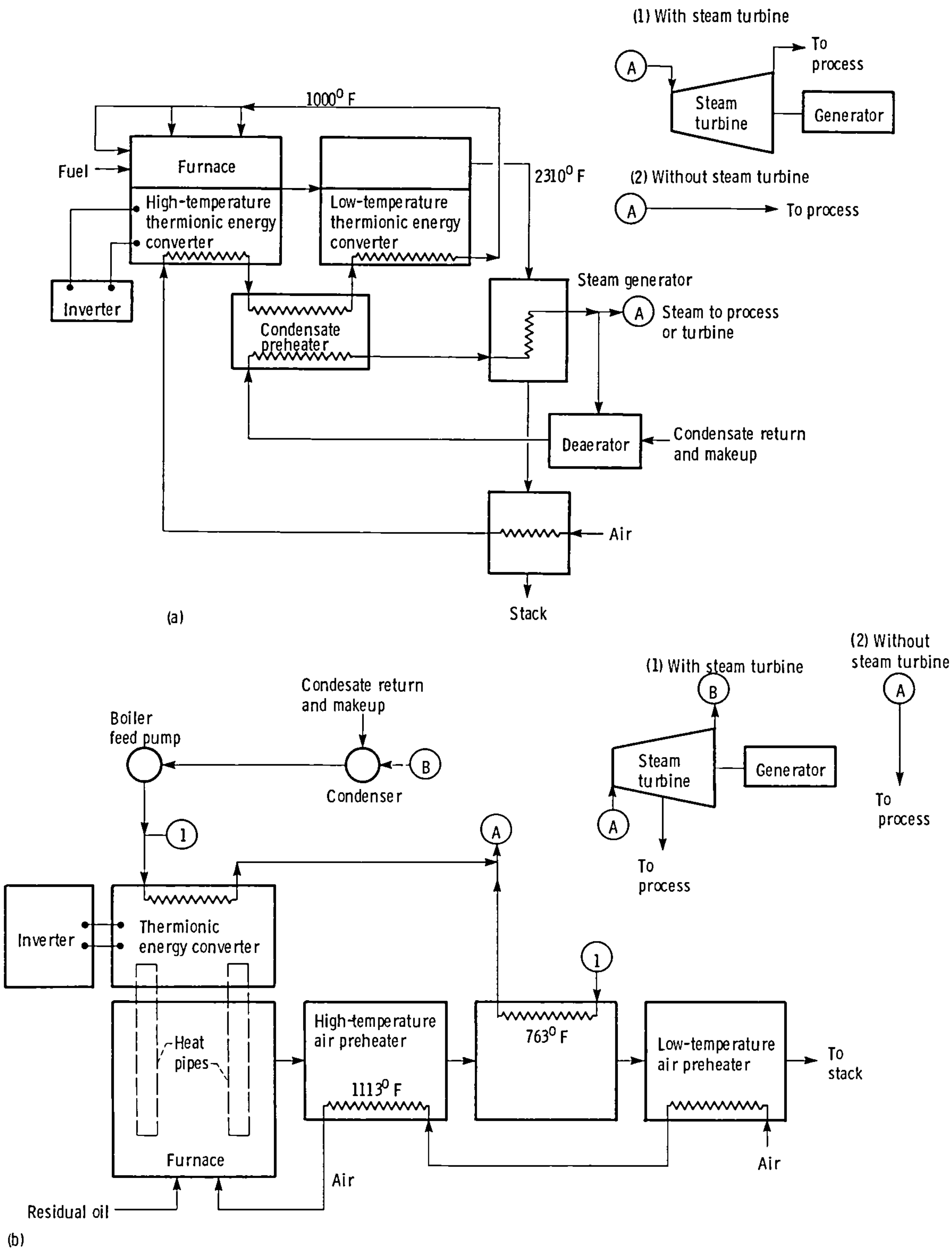
TABLE 5.9-3. - RANGE OF RESULTS FOR THERMIONIC POWER SYSTEMS USED WITH THE NINE REPRESENTATIVE INDUSTRIES

(a) No power export allowed

Energy conversion system subgroup	Contractor	Fuel energy saving ratio, FESR	Industry with maximum FESR	Emissions saving ratio, EMSR	Industry with maximum EMSR	Levelized annual energy cost, LAEC	Industry with maximum LAEC	Return on investment, ROI, percent	Industry with maximum ROI
Thermionic residual	GE	4-18	Malt beverage	All negative	--------	4-20	Malt beverage	All zero	--------
	UTC	Negative to 21	Meat packing	Negative to 8	Chlorine	1-31	Meat packing	0-15	Chlorine
Thermionic/steam turbine/ residual	GE	8-30	Writing paper	All negative	--------	9-32	Writing paper	0-14	Petroleum
	UTC	2-25	Chlorine	Negative to 4	Bleached Kraft	5-37	Bleached Kraft	0-73	Bleached Kraft
Thermionic/coal (FGD)	GE	5-22	Writing paper	Negative to 9	Petroleum	Negative to 13	Writing paper	0-8	Petroleum
Thermionic/steam turbine/ coal (FGD)	GE	13-20	Writing paper	Negative to 19	Petroleum	3-22	Writing paper	0-12	Petroleum

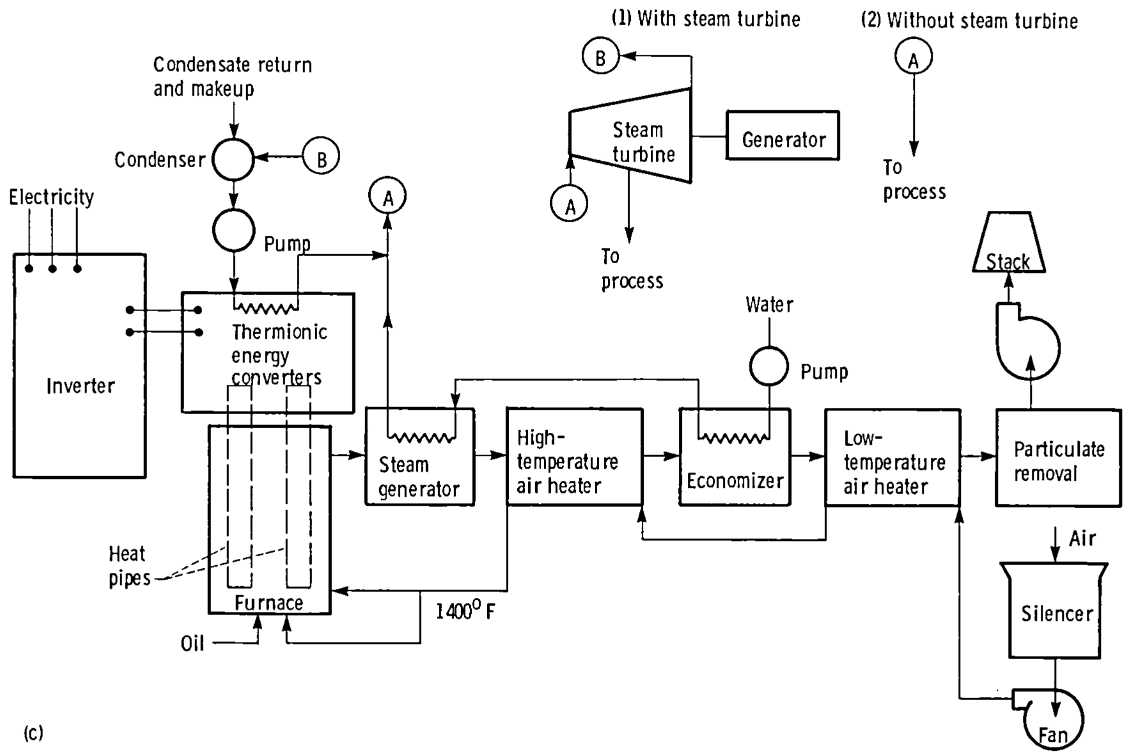
(b) Power export allowed

Energy conversion system subgroup	Contractor	Fuel energy saving ratio, FESR	Industry with maximum FESR	Emissions saving ratio, EMSR	Industry with maximum EMSR	Levelized annual energy cost, LAEC	Industry with maximum LAEC	Return on investment, ROI, percent	Industry with maximum ROI
Thermionic/residual distillate	GE	4-18	Malt beverage	All negative	--------	4-20	Malt beverage	0	----------
	UTC	Negative to 24	Malt beverage	Negative to 8	Chlorine	Negative to 37	Meat packing	0-15	Chlorine
Thermionic/steam turbine/ residual	GE	8-37	Malt beverage; meat packing	All negative	--------	9-39	Malt beverage; meat packing	0-4	Petroleum
	UTC	2-27	Petroleum	Negative to 4	Writing paper	5-44	Chlorine	0-7	Writing paper
Thermionic/coal (FGD)	GE	5-22	Writing paper	Negative to 9	Petroleum	Negative to 13	Bleached Kraft	0-8	Petroleum
Thermionic/steam turbine/ coal (FGD)	GE	13-40	Writing paper	Negative to 19	Petroleum	3-35	Writing paper	0-12	Petroleum



(a) GE.
(b) UTC (ceramic heat exchanger).

Figure 5.9-1. - Schematics of thermionic power systems.



(c) UTC (metal heat exchanger).

Figure 5.9-1. - Concluded.

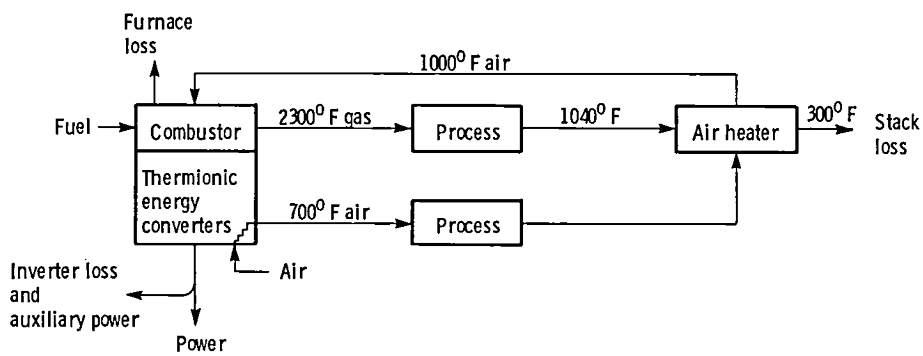
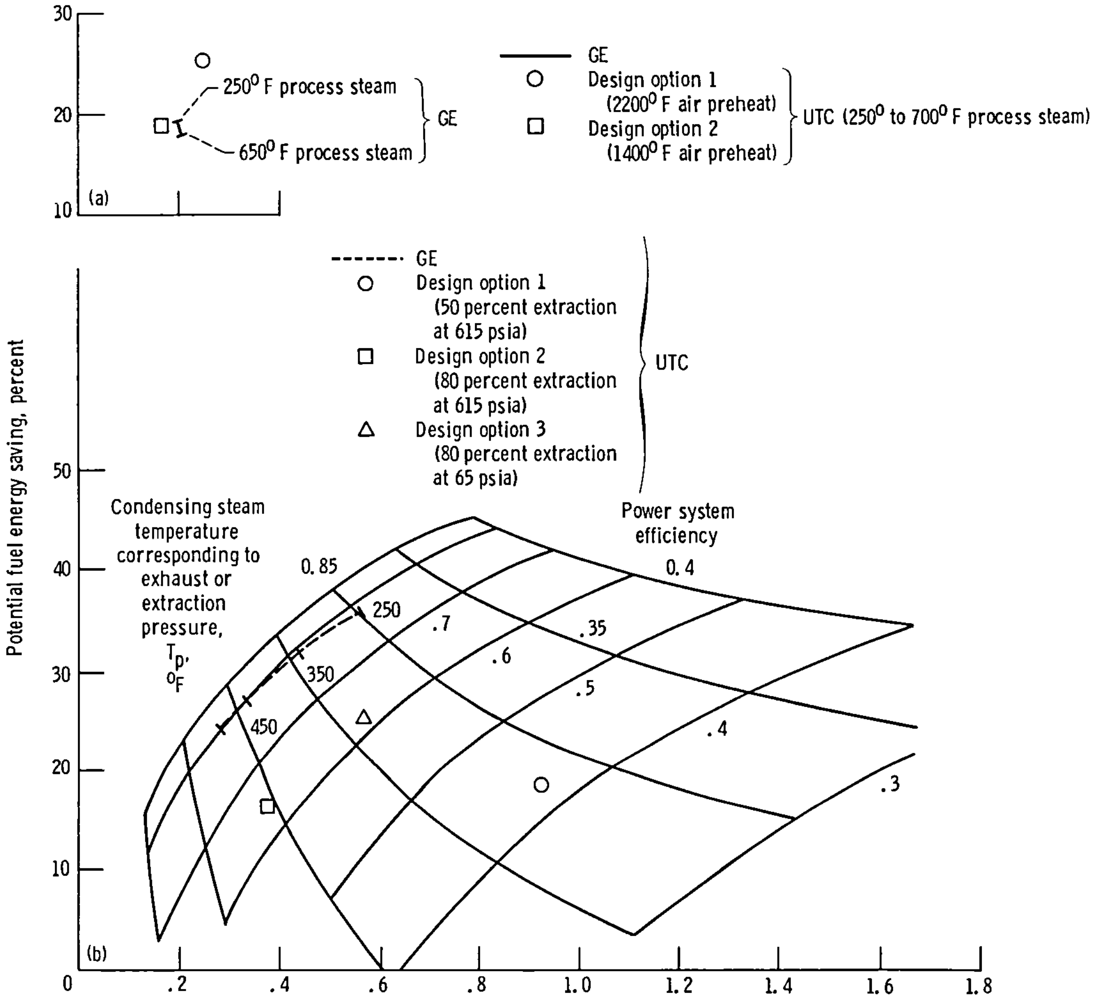


Figure 5.9-2. - Thermionic power system for direct heat supply.



(a) Without steam turbine.
(b) With steam turbine.

Figure 5.9-3. - Performance characteristics of thermiconic power systems. For noncogeneration case: boiler efficiency, 83 percent; utility efficiency, 32 percent.

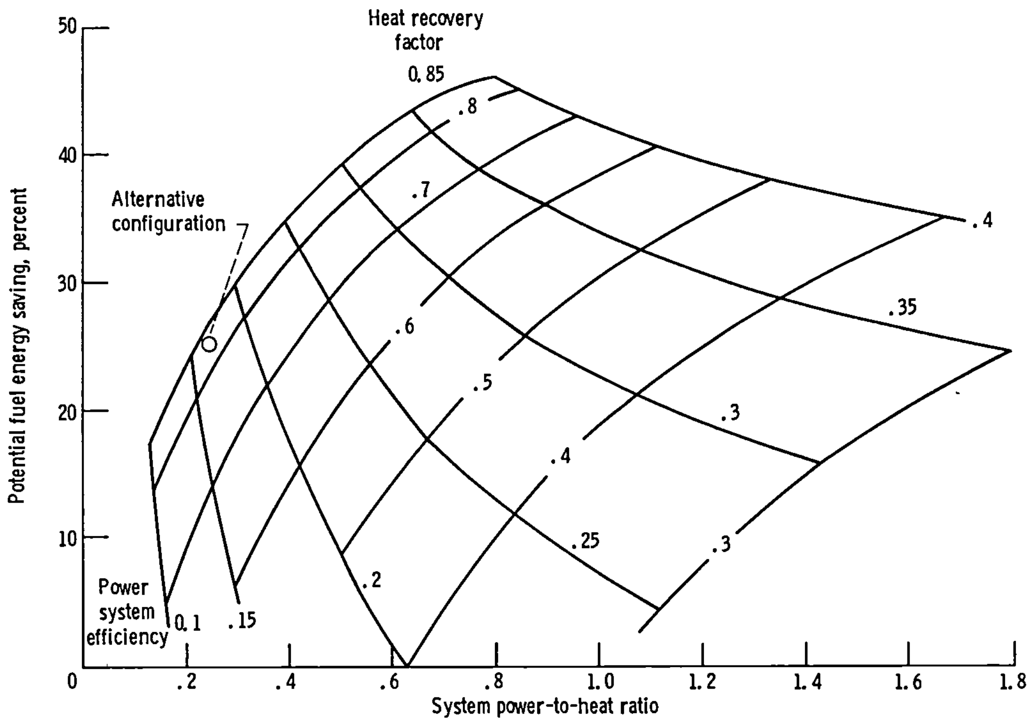
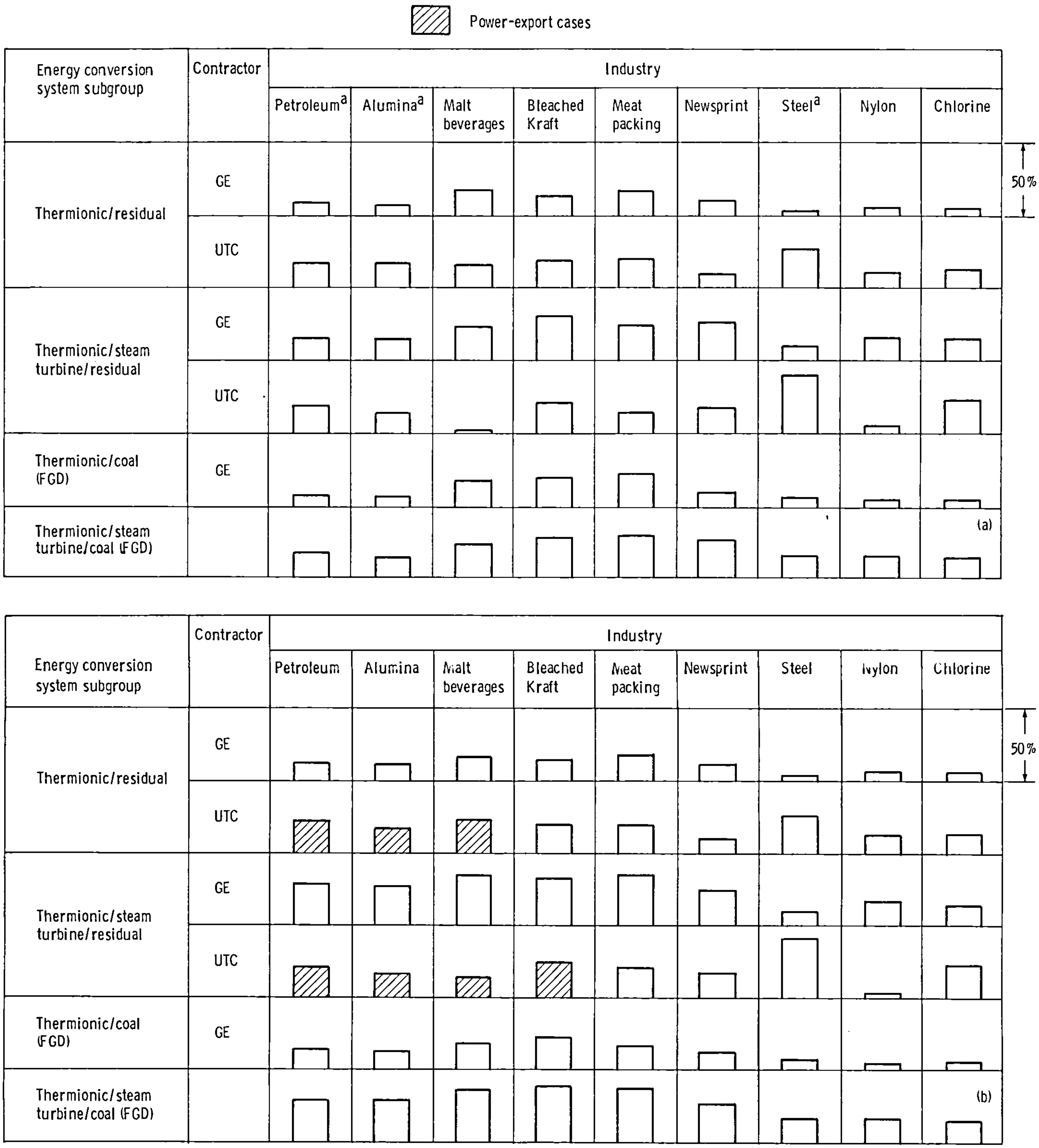


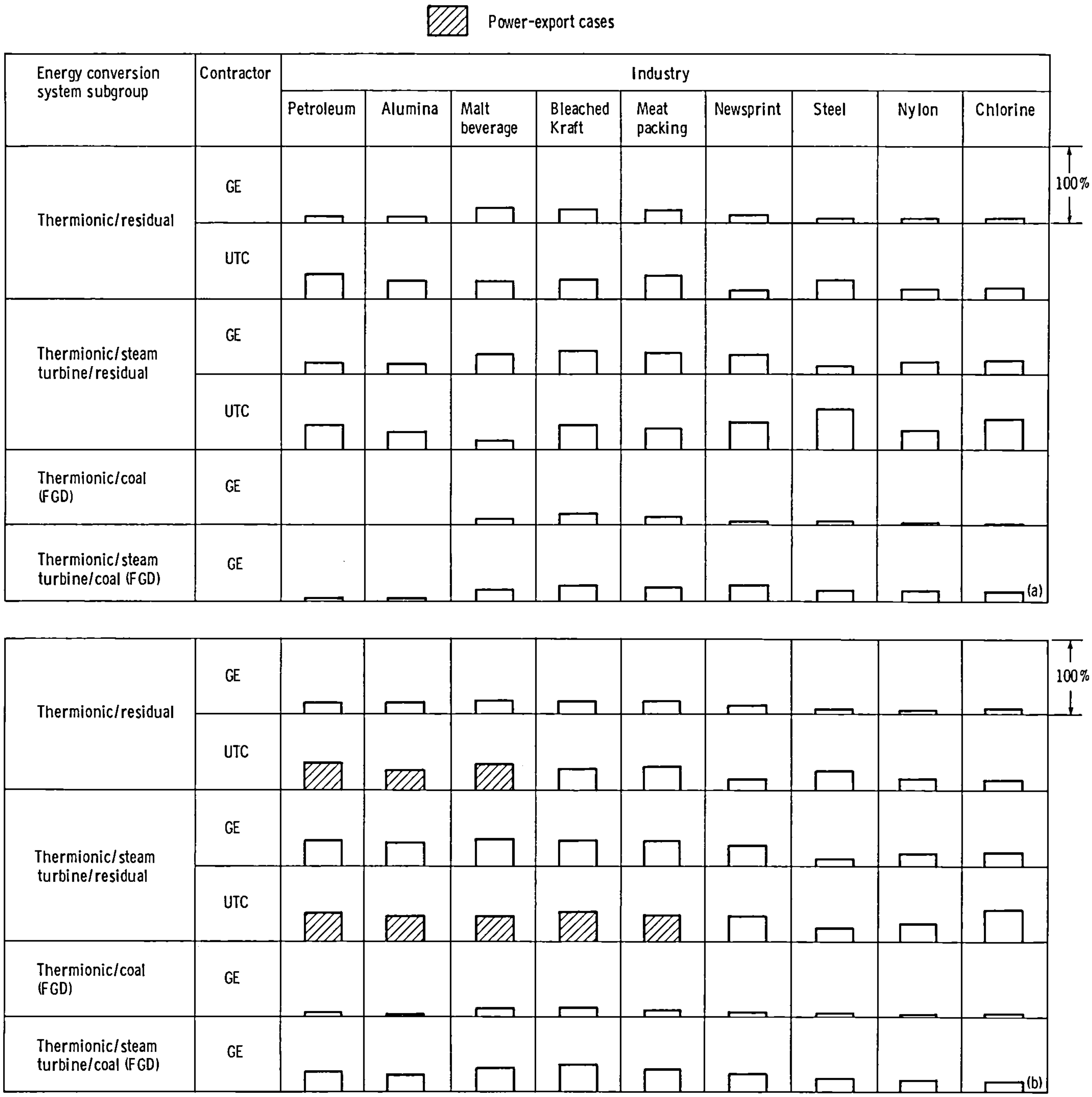
Figure 5.9-4. - Performance characteristics of thermionic power systems for direct-heat supply. For noncogeneration case: boiler efficiency, 85 percent; utility power efficiency, 32 percent.



[a] UTC results were modified by NASA.

(a) No power export allowed.
(b) Power export allowed.

Figure 5.9-5. - Fuel energy saving ratio for thermionic power systems.



(a) No power export allowed.
(b) Power export allowed.

Figure 5.9-6. - Emission saving ratios for thermionic power systems. (Blanks denote all negative values.)

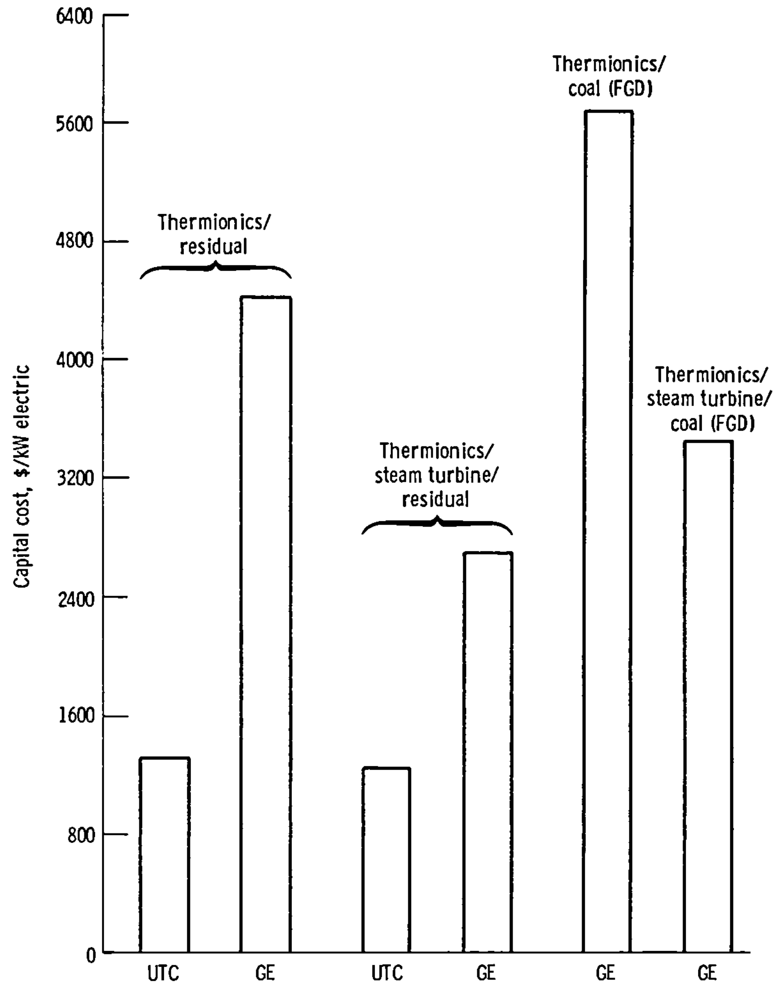


Figure 5.9-7. - Capital costs for thermionic systems. Electricity generated, 10 MW; process steam temperature, 300° F.

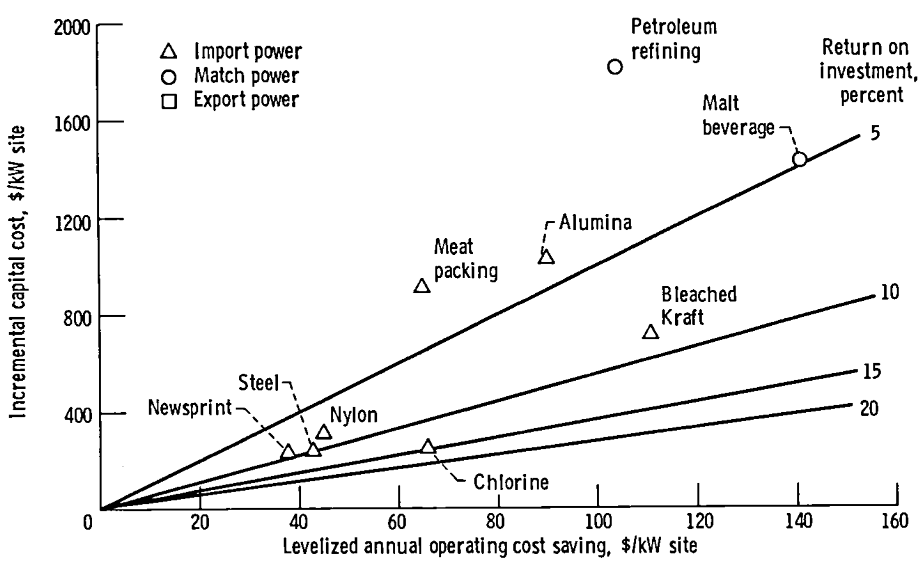
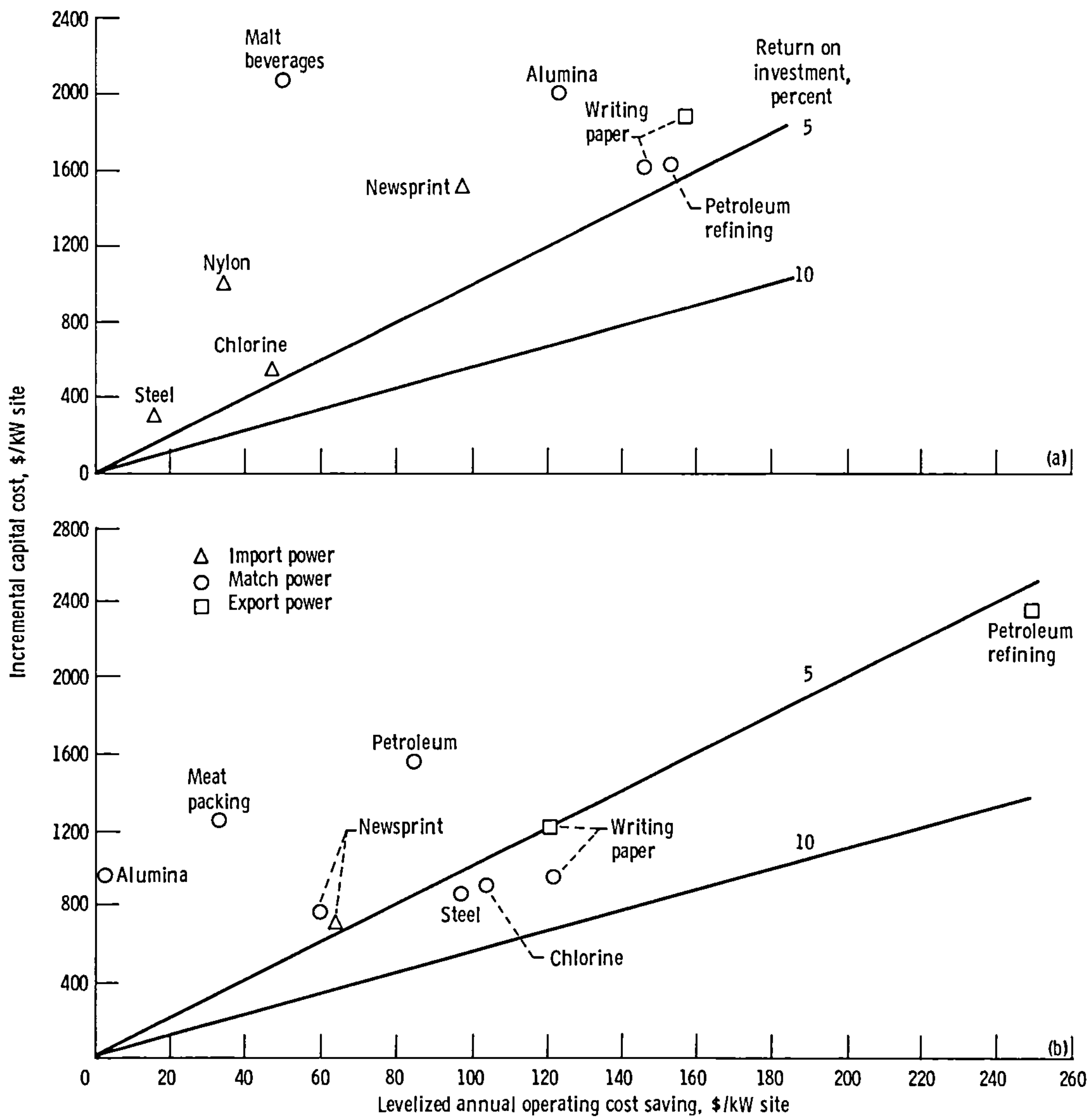
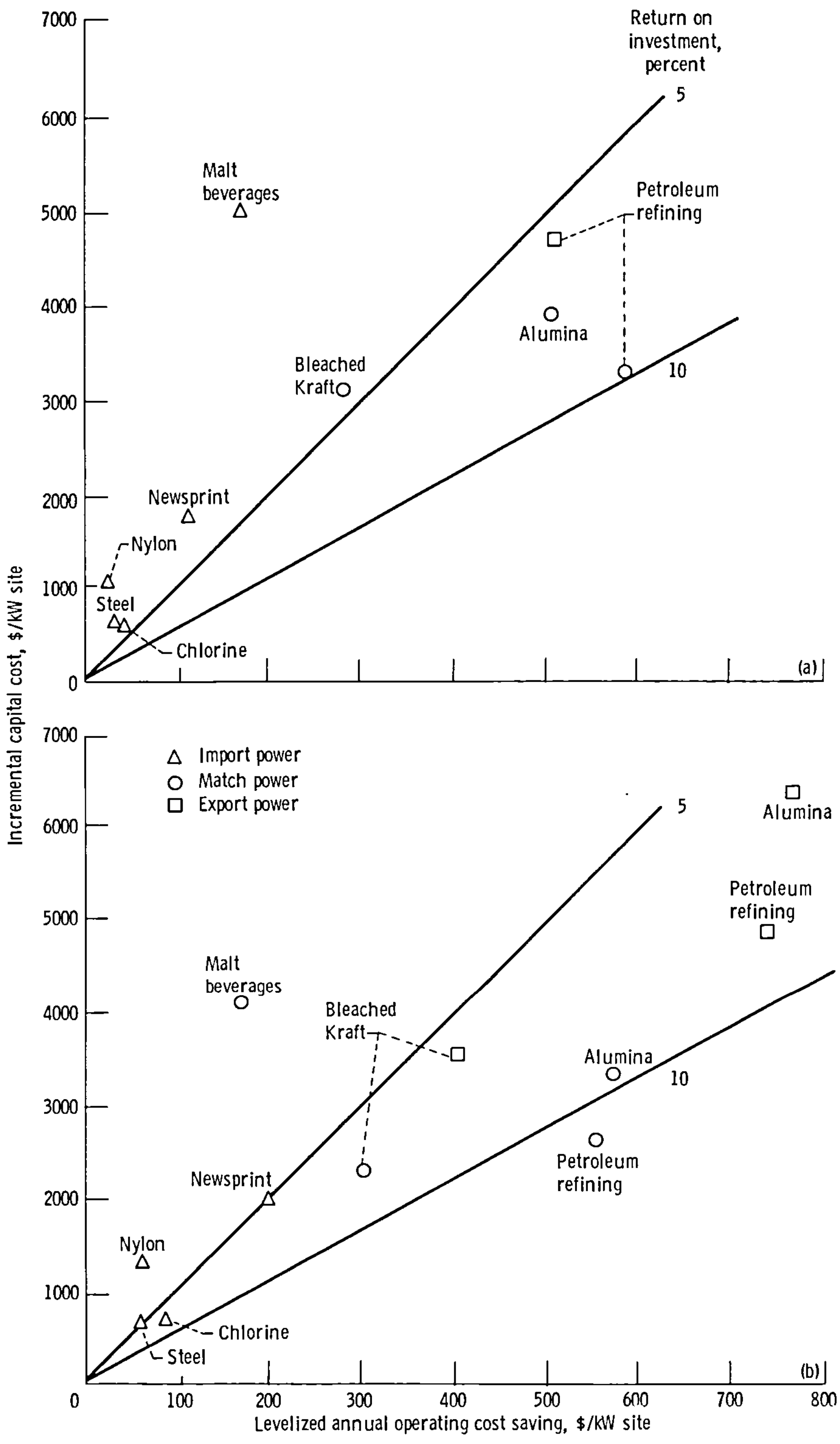


Figure 5.9-8. - Incremental capital cost as a function of levelized annual operating cost saving for UTC's thermionic/residual systems.



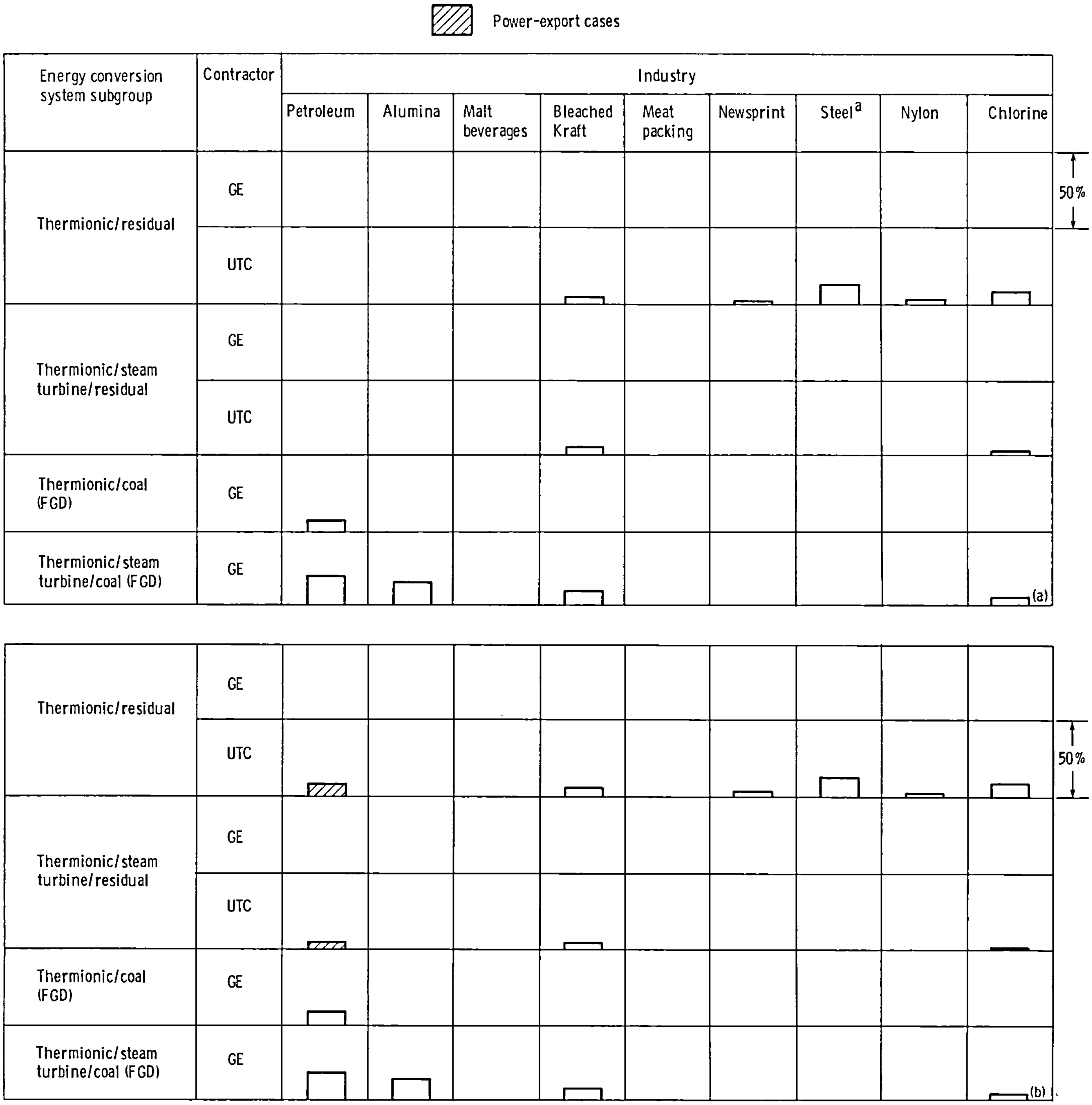
(a) GE.
(b) UTC.

Figure 5.9-9. - Incremental capital cost as a function of levelized annual operating cost saving for thermionic/steam turbine/residual systems.



(a) Without steam bottoming cycle.
(b) With steam bottoming cycle.

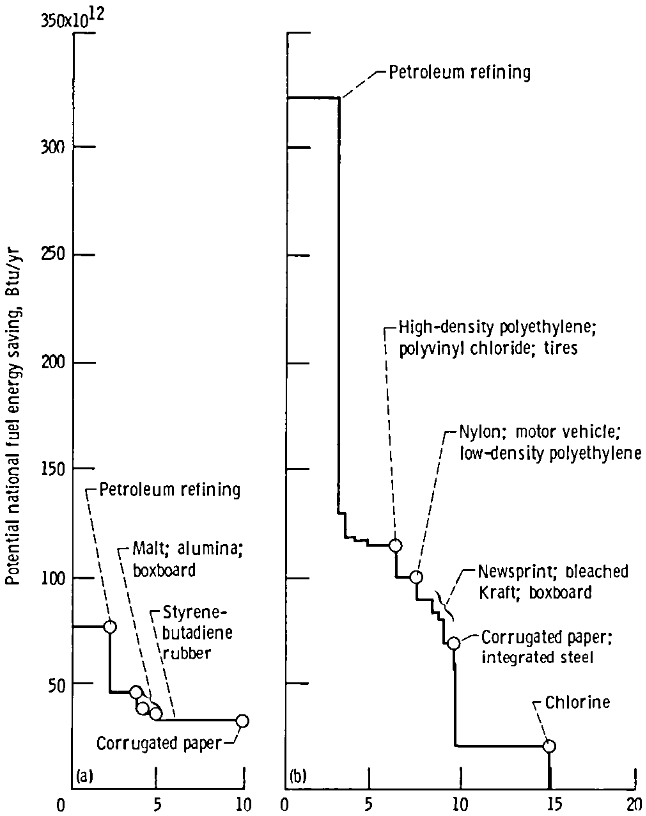
Figure 5.9-10. - Incremental capital cost as a function of levelized annual operating cost saving for GE's thermionic/coal system.



[a] Modified by NASA

(a) No power export allowed.
(b) Power export allowed.

Figure 5.9-11. - Levelized annual energy cost saving ratios for thermionic power systems. (Blanks denote all negative values.)



(a) Match power.
(b) Maximum-fuel-energy-saving-ratio strategy.

Figure 5.9-12. - Potential national fuel energy saving as a function of hurdle return on investment for UTC's thermionics/HRSG/residual systems.

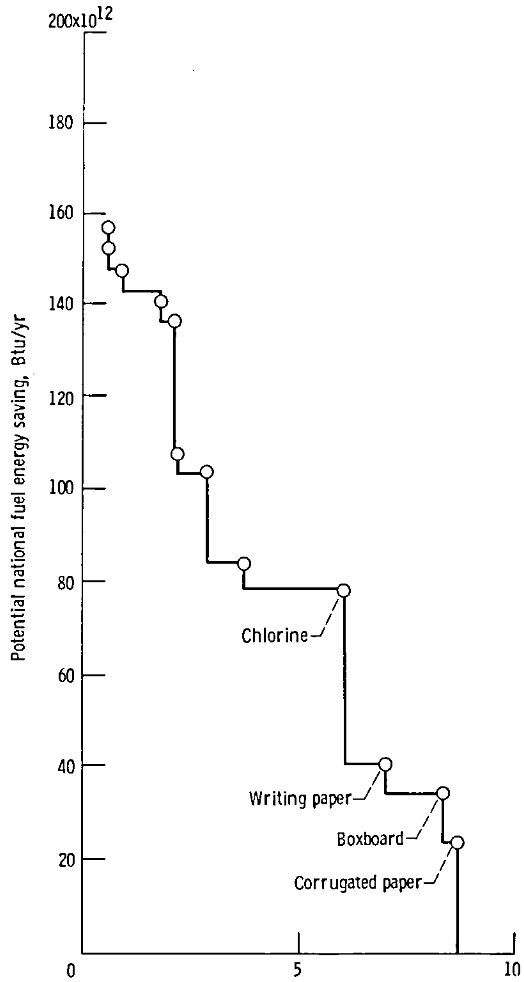


Figure 5.9-13. - Potential national fuel energy saving as a function of hurdle return on investment for UTC's thermionic/steam turbine/residual systems. (Match power.)

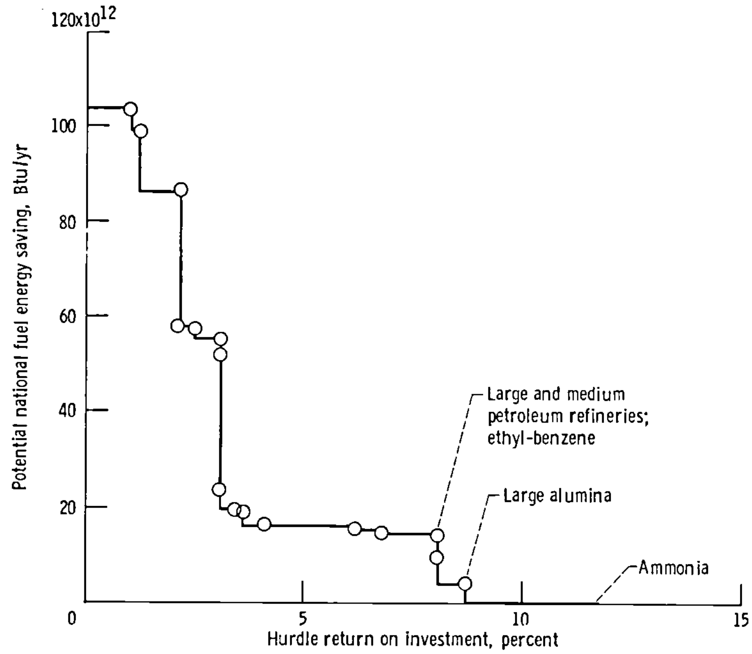


Figure 5.9-14. - Potential national fuel energy saving as a function of hurdle return on investment for GE's thermionic/HRSG/coal (FGD) systems. (No power export allowed.)

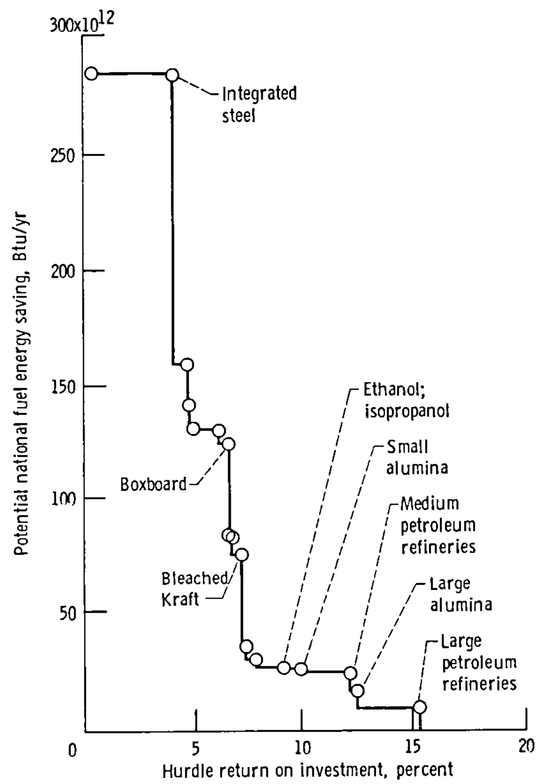


Figure 5.9-15. - Potential national fuel energy saving as a function of hurdle return on investment for GE's thermionic/steam turbine coal systems. (No power export allowed.)

6.0 EVALUATION OF STUDY RESULTS

This section compares the advanced energy conversion systems studied by General Electric and United Technologies, presents the results of the evaluation process used by NASA to identify the most attractive advanced systems for industrial cogeneration, and discusses the benefits of the advanced systems as compared with systems employing current commercially available technology.

Section 6.1 presents plant-basis results from the study with emphasis on results for the systems that were found attractive by using the Lewis screening methodology. Section 6.2 presents results on a national basis. Section 6.3 identifies the most attractive advanced energy conversion systems based on Lewis' evaluation of both plantand national-basis results and also identifies potentially attractive industrial process applications. Section 6.4 illustrates some of the potential benefits of advanced systems as compared with today's commercially available technology.

6.1 PLANT-BASIS RESULTS

John W. Dunning

The most attractive systems found for the nine representative industrial process plants used by Lewis in their detailed screening of plant-basis results are shown in figure 6.1-1. The coal-fired systems are shown in part (a) and the systems using coal-derived liquid fuels are shown in in part (b). For each industrial process, Lewis screened the results from each contractor individually and independently and then judged whether a system was among the most attractive for that industry. Analyses performed by Lewis to supplement or confirm the contractors' results or to reconcile differences in them were used as a guide in these decisions, particularly when there were differences in the contractors' results. In those cases where contractors' results differed enough to make one contractor's results for some system attractive enough to survive the screening process while the other contractor's results did not, the results were examined to determine the reason for the differences before it was decided whether to include that system in figure 6.1-1.

As discussed in section 3.2 the nine industry processes in figure 6.1-1 cover a wide range of sizes, power-to-heat ratios, and steam pressure requirements. They are arranged in the figure roughly from the lowest to the highest power-to-heat ratio (with heat being in the form of steam and hot water). The figure indicates the range of industries in which each system was able to attain results attractive enough to survive the screening. Systems not listed in the figure may have achieved attractive results in some industries in terms of one or more of the output parameters but were not among the overall most attractive cases.

At least one cogeneration case survived the screening process for each of the nine industry processes considered. Also each process except meat packing and nylon had both coal-fired and coal-derived-liquid-fueled attractive cases. For these two industries the plant-site data resulted in coal-fired cases with relatively poor economics. Both the meat packing plant and the nylon plant required relatively small amounts of electricity, and this resulted in higher power system specific cost. In addition, the meat packing plant operated for

a relatively few hours per year. Since the annual operating cost saving relative to the capital investment is directly proportional to the hours of operation per year, the economics of cogeneration are more attractive when the hours of operation per year are high. Furthermore, the nylon process requires a power-to-heat ratio that is higher than the ratio produced by most of the coal-fired energy conversion systems studied. In such a case either the power system produces only part of the power needed, or only part of the heat potentially recoverable from the power system is usefully recovered. In either case the fuel saving is relatively low and hence the yearly operating cost saving is also relatively low.

The results for each system appearing in figure 6.1-1 are listed in table 6.1-1 for each of the nine representative industries where attractive results were achieved. These results are based on the use of a coal-derived residual liquid fuel in the noncogeneration onsite boiler. In general the values shown for each parameter are high since they correspond only to the most attractive cases identified in the screening process. The values given for the pressurized-fluidized-bed (PFB) steam system (table 6.1-1(b)) correspond only to GE's results since UTC did not study this configuration. Similarly, the values given for the coal-fired, open-cycle gas turbines (tables 6.1-1(d) to 6.1-1(f)) correspond only to the UTC results since GE did not study such cases. Also shown is the sizing strategy that was used in matching each energy conversion system to each industrial process. The terms "export" and "import" indicate that the system is sized such that it produces either more or less electricity than is required by the industrial site, resulting in either the sale or purchase of electricity. The term "match power" indicates that the system is sized to match the electric power requirement of the industrial process.

The results for the most attractive steam turbine cogeneration systems with atmospheric fluidized beds are shown in table 6.1-1(a). Only the results for the GE steam turbine/AFB system are shown since the UTC system does not achieve attractive results in any of the nine representative industries. The UTC system uses an extraction condensing steam turbine; the GE systems use a noncondensing back-pressure steam turbine (section 5.1). The UTC system results in lower cogeneration performance than GE configurations when matched to industries with low power-to-heat ratios. UTC also included steam turbine performance reductions for power system sizes less than 30 MW electric; GE did not include performance penalties at the smaller sizes. In many cases steam is extracted from the UTC steam turbine at steam pressures considerably higher than required by the process, and this further penalizes the performance of the UTC steam turbine (section 5.1). Also, the auxiliary power requirements estimated by UTC for their system were higher than those estimated by GE. Thus substantial differences between the results of the two contractors come from the combined effects of these different approaches.

As shown in table 6.1-1 GE's steam turbine/AFB system achieves its most attractive results in industries with relatively low required power-to-heat ratios because, as mentioned in section 5.1, the steam turbine/AFB system has a low power-to-heat ratio.

The results for the most attractive steam turbine/PFB systems are shown in table 6.1-1(b). The steam turbine/PFB systems achieve attractive results in industries with a wider range of required power-to-heat ratios than those industries where the steam turbine/AFB systems look attractive. The reasons are

the generally higher power-to-heat ratios produced by the PFB systems and their generally higher potential fuel energy savings as compared with the AFB systems (section 5.1).

The results for the most attractive gas turbine/ AFB systems are shown in table 6.1-1(c). UTC's petroleum process needs a considerable amount of direct process heat, and UTC assumed that a large portion of the turbine exhaust could be used to satisfy that requirement. This resulted in very good heat recovery from the gas turbine and the consequent high output parameters in the petroleum industry. The high values of these parameters in the writing paper industry result from a UTC assumption that a black-liquor byproduct fuel derived from the paper industry can be burned in the AFB.

The results for the most attractive gas turbine/PFB systems are shown in table 6.1-1(d). UTC's gas turbine/PFB system achieves attractive results in more industries representing a wider range of required power-to-heat ratio than the gas turbine/AFB system shown in table 6.1-1(c). As shown in section 5.2 the PFB system generally produces a higher power-to-heat ratio and achieves higher potential fuel energy savings than UTC's AFB system. This makes the PFB system more applicable to a wider range of industries.

The results for the most attractive gas turbine cogeneration system with an integrated gasifier are shown in table 6.1-1(e). This system achieves its most attractive results in the writing paper industry because of the close match of the power-to-heat ratio produced by the system with that required by this industry.

The results for the closed-cycle gas turbine/AFB system are shown in table 6.1-1(f). Only the values for the UTC system are shown since the results for the GE closed-cycle gas turbine/AFB system were not attractive. UTC used a 190° or 300° F compressor inlet temperature as compared with 80° F used by GE, and this higher temperature reduces the amount of heat rejected by cooling towers to the atmosphere in the UTC case. The resulting power-to-heat ratio is a much closer match to the requirements of the writing paper and newsprint industries, where the system looks most attractive, and results in higher fuel savings and higher annual operating cost savings. The use of byproduct fuel from these two processes in the AFB also contributes to the attractive cogeneration performance. The configuration used by GE would look relatively better in situations where heat is recovered in the form of hot water. Also, the UTC capital cost estimates are lower than those of GE.

Results for the most attractive molten carbonate fuel cell systems with an integrated gasifier are shown in table 6.1-1(g). The GE results show attractive cogeneration performance and economics in the petroleum and alumina industries. The direct-heat requirements caused the poor fuel energy savings, and the high capital cost resulted in the poor economics in the other industries. The UTC system achieves attractive cogeneration results in the newsprint industry because the power-to-heat ratio produced by the UTC system closely matches that required by UTC's newsprint industry at a certain process steam temperature. Not that te emissions sabing ratios for the molten carbonate fuel cell with integrated gasifier are extremenly high (somethimes approaching 100 percent) because of teh high fuel cleanliness required by the fuel cell.

The most attractive results for the advanced, residual-fueled gas turbine systems are shown in table 6.1-1(h). Both contractors' results indicate attractive applications in nearly every one of the nine representative idustries. The results for both contractors are generally very similar, with the exception of the emissions saving ratio. UTC assumed the development of NO_x-limiting combustors and thus included a reduction in NO_x from fuel-bound nitrogen that is consistent with DOE development goals. NO_x emission values used by UTC meet the emissions limit set for the study. GE assumed a be substantial reduction in NO_x formation as compared with what would be produced if all the fuel-bound nitrogen were converted to NO_x, but the NO_x emissions values they estimated for the coal-derived fuels exceed the emissions limit set for the study. The results for UTC's steel industry are considerably higher than those for other industries because UTC assumed the use of byproduct coke oven fuel gas in the cogeneration system.

The most attractive results for the advanced combined-cycle system burning residual fuel are shown in table 6.1-1(i). Because of the higher power-to-heat ratio produced by this system, it had its most attractive results with industries having a relatively high required power-to-heat ratio. As mentioned previously for the gas turbine systems using residual fuel, the results for the combined-cycle systems of both contractors are similar, with the exception of UTC's higher emissions saving (because of lower NO_x emissions estimates) and the higher values achieved by UTC's steel industry (because of the use of coke oven gas byproduct fuel in the energy conversion system).

The results for the most attractive molten carbonate fuel cell cogeneration systems using distillate fuel are shown in table 6.1-1(j). Only UTC results are shown since the GE system did not achieve attractive results. The configuration studied by UTC was one in which a portion of the anode exhaust is fed to the adiabatic reformer. The water vapor in the gas eliminates the need for a separate steam input. Thus the resulting power-to-heat ratio produced by the steam closely matches those required by the industries shown in table 6.1-1(j). The configuration studied by GE uses a portion of that generated process steam for the reformer. Less steam is available for processes, and a high system power-to-heat ratio is required. This results in much lower fuel and operating cost savings and, together with a higher GE capital cost estimate, results in the GE cogeneration system being less attractive.

In this section results have thus far been given only for those systems found attractive on the basis of the Lewis screening. An important concern at this point is to convey briefly how the other advanced systems compare with those identified in figure 6.1-1. In fact, the various other advanced systems often show attractive results in a number of process applications. However, in general, wherever one of the other advanced systems shows attractive results, one or more of those systems identified in figure 6.1-1 show superior results. This fact is illustrated in tables 6.1-2 and 6.1-3 for the GE and UTC results, respectively. In part (a) of each table the most attractive application for each of the other advanced systems is identified along with the return on investment and fuel energy saving estimated by the contractor. Part (b) of each table gives the results achieved by the most attractive system in the corresponding process applications identified in part (a). Where both a coal-fired and a coal-derived-liquid-fueled system appear in part (a), the most attractive coal-fired and coal-derived-liquid-fueled systems are each included in part (b). In almost all cases both the return on investment and fuel energy saving are higher for the advanced systems shown in figure 6.1-1.

The sensitivity of results to changes in ground rules and assumptions was examined by each contractor and by Lewis. The variables examined included fuel prices, the price of purchased electricity, the price received for exported electricity, capital costs, investment tax credit, tax life, inflation rate, and the escalation rate of fuel and electricity prices relative to the general inflation rate. Of prime consideration was whether changes in the ground rules and assumptions would affect the relative comparisons of the advanced energy conversion systems.

Changes for such parameters as investment tax credit, tax life, inflation rate, and across-the-board changes in fuel and electricity prices caused changes in the absolute values of the results but did not significantly alter the comparisons of the advanced systems. Changes in the relative prices of the different fuels or changes in the relationship between the prices of exported and purchased electricity had a more significant effect on the comparison of systems, particularly the comparison of coal-fired versus coal-derived-liquid-fueled systems. In addition to having a more pronounced effect on the relative results for the various advanced systems, future fuel and electricity prices have a great uncertainty associated with their values. This is one reason why the results presented in this report have been placed into two groups according to whether the system burns coal or coal-derived liquid fuel. Within these two groups, relative comparisons of the various systems were not significantly altered over wide changes in fuel and electricity prices. Appendix E illustrates the sensitivity of the results to changes in fuel and electricity prices.

6.2 NATIONAL-BASIS RESULTS

John W. Dunning and Annie J. Easley

Although the emphasis in the study was on development of data on a plant basis, relative comparisons of the various advanced systems in terms of potential benefits on a national scale were also viewed as important. Each contractor aggregated his plant-basis results to the national level. Included in the estimates made by the contractors for each system were the possible energy savings, emissions savings, and annual cost savings. To obtain relative comparisons among the various advanced systems without clouding individual plant differences, each energy conversion system was considered individually by the contractors and applied to every process studied without competition. These results were then aggregated and extrapolated to all industries including those processes not specifically included in the study. This last extrapolation was subject to many assumptions and prevented a direct comparison of the contractors' results.

To provide a direct comparison of the contractors' results, NASA used the contractors' plant-basis results as input to an analysis that considered only those processes specifically included in the contractors' results without the uncertainty involved in extrapolation to other processes. This approach yielded "national basis" results that were considerably lower than the contractors' results. The differences are attributable to the specific assumptions and methodology used.

By assuming that the savings or advantages of the cogeneration system in a representative plant could apply to all manufacturing plants producing the same commodity, potential savings at the process level can be estimated. The results of this analysis are shown in figures 6.2-1 to 6.2-6. Fuel savings are indicated in figures 6.2-1 and 6.2-2, cost savings in figures 6.2-3 and 6.2-4, and emissions savings, in figures 6.2-5 and 6.2-6. Each figure is divided into two parts. Part (a) presents the GE-based results; part (b), the UTC-based results. For each conversion system three bars are presented. The top bar indicates the potential saving if the return on investment (ROI) is required to be zero or greater. The middle bar requires an ROI of 10 percent or greater. The bottom bar requires an ROI of 20 percent or greater. The odd-numbered figures (6.2-1, -3, and -5) present results for those cases that do not allow export of electricity. The even-numbered figures (6.2-2, -4, and -6) present results for those cases that allow export of electicity. The assumptions and methodology used to derive these figures are described in section 4.4. In examining these results, bear in mind that relative comparison of systems on a consistent basis was the prime consideration. The absolute magnitude of the results could be significantly higher or lower depending on the scenario for implementation of cogeneration systems into a market and the assumptions used to predict the size of the market. In each figure the conversion systems are segregated according to fuel type and arranged in descending order of fuel energy savings.

6.2.1 Fuel Energy Saving

The relative fuel energy savings for the advanced systems with no export of electricity are shown in figure 6.2-1. Many systems show high energy savings if all applications with an ROI greater than zero are included. Both contractors' results show high energy savings for the molten carbonate fuel cell system, the liquid-fueled gas turbine and combined-cycle systems, and the advanced diesel systems. Although the systems are included in the GE study, no results are shown for the phosphoric acid or molten carbonate fuel cells using coal-derived liquid fuels since no cases resulted in an ROI greater than zero. The potential savings with the molten carbonate and diesel systems are zero or near zero if an ROI of greater than 20 percent is required for an installation. In fact potential energy savings for all systems decrease at higher required levels of ROI. The systems that do look good for an ROI of 20 percent are primarily the systems that have already been identified as attractive on the basis of the plant-site screening.

The same type of national-basis results for energy savings with the export of electricity is presented in figure 6.2-2. The savings in figure 6.2-2 are typically 2-1/2 to 5 times those shown in figure 6.2-1 (export not allowed). The GE molten carbonate fuel cell systems and the UTC gas turbine/gasifier system, which show considerable savings without export of electricity, show even more savings with export by a factor of about 3. The savings for the gas turbine/gasifier are primarily due to savings in the energy-intensive petroleum industry. Comparing the bars for ROI > 20 percent and ROI > 0 shows a greater reduction in fuel savings than in figure 6.2-1. This is primarily caused by the economic ground rule that assumed the price obtained for electricity sold to the utility is 60 percent of the price that the industry pays for electricity. A higher sell-back price would cause many more systems to become attractive at high ROI. The power system, in matching the thermal needs of the site,

often generates two to four times the power required by the site. The advanced power systems, by being generally more efficient than their conventional-technology counterparts, produce more electricity per Btu of fuel and per Btu of waste heat. If the power-to-heat ratio of the industry is low (i.e., more Btu's of steam required than Btu's of electricity), matching the thermal needs of the site with a power system producing a high power-to-heat ratio creates a mismatch between the industry and the power system that causes excess power to be generated on site. Some installations, with a large mismatch in power-to-heat ratios, generate 5 to 10 times the power needed on site. The economics of these situations might warrant consideration of utility ownership of a portion of the power system. The Public Utilities Regulatory Policy Act (PURPA) allows for utility ownership of up to 50 percent of the cogeneration system.

6.2.2 Cost Saving

The cost comparisons are presented in figures 6.2-3 and 6.2-4. The conversion systems are arranged in the same order in these figures as in figures 6.2-1 and 6.2-2 (i.e., top to bottom in descending order of fuel energy saving by fuel type).

As studied, the annualized initial capital cost of the cogeneration equipment was not low as compared with the fuel cost in several cases. In the GE study the thermionic topped steam turbine was not economically attractive, even when burning inexpensive coal. The liquid-fueled advanced diesel engine, which saved significant amounts of fuel, was not economical for any positive required rate of return. If export is allowed, the same power systems are not economically attractive on the basis of the GE results.

The UTC data indicate that, of the coal-fired systems, the high-temperature fuel cell/gasifier combination cannot compete at high required rates of return with other coal-fired powerplants. In addition, four of the seven liquid-fueled systems are not economically attractive. The low-speed diesel has applications with positive cost savings particularly in the boxboard industry. Neither the GE nor UTC results show significant differences between the no-export and export situations. The analysis excludes any cost savings that may be seen by the utility as avoided operational or capital expenditures. The savings therefore represent only the savings seen by the plant manager though buying cheaper fuel or operating a more efficient power system. One then would not expect greater cost savings with systems that export large amounts of electricity. If the economic ground rules were changed to allow a higher purchase price for excess electricity, the systems with high power-to-heat ratios would become more economical.

6.2.3 Emissions Saving

The emissions saved at the plant site are shown in figures 6.2-5 and 6.2-6. There is little difference between export and no-export situations. The GE results indicate that the steam-bottomed molten carbonate fuel cell releases the least atmospheric emissions to the air. This is due to the extensive coal cleaning and gasification steps that precede power generation. The components of the coal that might cause pollution problems are removed as solid

waste before combustion of the coal in the fuel cell. The UTC results for the fuel cell/ gasifier indicate a similar phenomenon. For both studies the diesel power systems cannot meet the NO_x emission standard. Therefore the GE advanced diesel and the UTC low-speed diesel show negative emissions savings at the plant site.

The GE coal-fired steam turbines and liquid-fueled gas turbines have good emissions savings for the range of ROI considered. The same is true for the UTC coal-fired and liquid-fueled gas turbines. In general the emissions savings are essentially the result of the power system's greater fuel efficiency in producing the required power and heat than in the noncogeneration case. In most cases (fuel cells and diesels excepted) the emissions savings correlate well with the fuel savings. The nature of the fuel cleanup required for fuel cells causes their emissions savings to be proportionally larger than those for the other power systems. Conversely, by their nature the diesel combustion processes cause more emissions than would be expected from their attractive fuel energy saving ratios.

In summary, many of the power systems studied show significant national savings in fuel, cost, and emissions. Comparisons among systems have shown that several of the advanced systems studied are worthy of further study and development.

6.3 IDENTIFICATION OF MOST ATTRACTIVE ADVANCED ENERGY CONVERSION SYSTEMS AND POTENTIAL APPLICATIONS

Raymond K. Burns

From the contractors' results and independent in-house analyses an evaluation was made by Lewis to identify the most attractive advanced systems for industrial cogeneration that use coal or coal-derived fuels. As discussed and summarized in sections 6.1 and 6.2 the results were screened, analyzed, and evaluated both on an individual plant basis and on a national basis. Factors included in the evaluations were fuel energy saving, annual cost saving, emissions reductions, incremental capital cost, rate of return on incremental investment, applicability to a wide variety of industrial process requirements, and potential relative national impact. The attractive advanced energy conversion system and fuel combinations identified by Lewis are shown in table 1-1. The most attractive advanced energy conversion systems with the greatest potential for widespread implementation in industrial cogeneration were found to be the coal-fired steam turbine systems using atmospheric (AFB) or pressurized (PFB) fluidized bed furnaces and the open-cycle gas turbine and combined-cycle systems fired with a residual-grade, coal-derived liquid fuel. Additional attractive systems included several gas turbine and fuel cell concepts. These were open- and closed-cycle gas turbine systems with a high-temperature, coal-fired AFB heater; an open-cycle system with a high-temperature, coal-fired PFB heater; open-cycle gas turbine (or combined cycle) systems fired with low- or intermediate-Btu gas from a coal gasifier integrated with the system; and molten carbonate fuel cell systems using either low-Btu gas from an integrated gasifier or distillate-grade, coal-derived liquid fuel.

The ranges of results for the combinations of advanced energy conversion systems and fuels identified as attractive by Lewis are presented in tables 6.3-1 and 6.3-2. Results are given for each of the five major industry groups

appropriate for topping cogeneration applications that were emphasized for selection of representative process plants. Table 6.3-1 shows results without export of electricity to the utility grid; table 6.3-2 shows results with the export of electricity. In both tables the system configuration and cogeneration strategy were selected to maximize fuel energy savings. The ranges given are not for all of the industrial processes included in the study but rather summarize results for the attractive applications found in each of the five major industry groups. Applications were selected as attractive primarily on the basis of reasonably good combinations of fuel energy saving and ROI. These parameters, it was felt, would be strong indicators of overall attractiveness when considering other parameters as well. Although only ROI and energy saving are summarized in these tables, insight into results for the other parameters can be inferred from the material presented in appendix D. In tables 6.3-1 and 6.3-2 systems having applications with fuel energy savings greater than 10 percent and ROI's greater than 20 percent have been identified in order to indicate where the greatest potential for the systems exists. Comparing these tables shows that the ranges for fuel energy saving generally increase when export of electricity is allowed but the ranges of ROI generally decrease.

In a number of cases differences between results from the two contracted efforts are evident. These differences resulted from differences in the configurations studied by the contractors as well as from differences in the advancements in technology assumed; in the estimates for electrical efficiency, recoverable heat, and capital cost of the equipment; and in analytical procedures. Differences such as those shown were anticipated, and detailed examination of the results has provided added insight into the merits of the various systems. The differences and their effects on the results are discussed in section 5.0 of this report.

Potentially attractive industrial applications for the attractive advanced systems identified in table 1-1 are shown in tables 6.3-3 to 6.3-7. Each table shows where attractive results were obtained for processes included in the study in one of five major industry groups appropriate for topping-cycle cogeneration. The selection of the system configuration and cogeneration strategy used in preparing these tables was aimed at maximizing fuel energy savings and actually formed the basis for preparation of tables 6.3-1 and 6.3-2. Applications with ROI's greater than 20 percent and fuel energy savings greater than 10 percent are identified. An ROI greater than 20 percent was selected to indicate those cases with the greatest relative potential for industrial interest on economic grounds. It is not intended to imply that an ROI greater than 20 percent is required for implementation by industry or that all cases with ROI's greater than 20 percent would be attractive to a potential industrial owner.

Differences in attractive applications among systems are evident in tables 6.3-3 to 6.3-7. These differences are due to differences in the characteristics of the various systems that affect how well they can satisfy the different process requirements. As discussed in section 3.2 there is a great diversity of requirements in industry. Those systems that can satisfy a broad spectrum of requirements will have an advantage in the degree of implementation that can be achieved.

6.4 BENEFITS OF ADVANCED TECHNOLOGY

John W. Dunning

The results discussed thus far have consisted of sums of fuel, emissions, or cost savings for each energy conversion system applied in a single plant (section 6.1) or throughout all industry (section 6.2). The results indicate that there are good cogeneration prospects for each of the conversion system technologies in specific industrial process applications. National results are presented for a scheme that allows different conversion systems to be used in each CTAS industry; recognizing that some industry/cogeneration system matches are better than others. The benefits of advanced technology in industrial cogeneration as compared with the use of commercially available equipment are discussed primarily from the national perspective in this section by using a criterion that satisfies these goals. As mentioned in the previous section, potential benefits were extrapolated only for the industrial processes explicitly included in the CTAS study. The methodology was as follows: For each industry studied by each contractor, the energy conversion system with the largest positive fuel energy saving ratio that also had a return on investment greater than an assumed "hurdle" rate was assumed to be implemented in that industry. Each industry could therefore use a different cogeneration system. It could be current technology or it could be advanced technology, depending on the values of fuel energy saving ratio (FESR) and ROI. If no cogeneration system had a positive FESR and an acceptable ROI, the industry was not included in the results.

An example of the selection process is shown in table 6.4-1, which uses data from the United Technologies CTAS study. The first column of the table from the Standard Industrial Classification code is an index of the industry. The second column give the name of the energy conversion system that has the highest fuel energy saving ratio for the particular industry. The fuel energy saving ratio is shown in the third column. By using appropriate scaling factors the fuel energy savings can be scaled to a national level. The assumptions and methodology used to scale the results are described in section 4.4. The total fuel saving for a particular industry is shown in the fourth column. Those industries for which there is no entry had a negative fuel energy saving ratio or an ROI lower than the "hurdle" rate for any energy conversion system. By summing the fourth column it is possible to get the total national fuel saving for this approach for the combinations of industry and energy conversion system shown in the table.

By using this basic approach additional insight into the merits of advanced systems can be obtained from the results of the study. For example, one can restrict the selection of energy conversion systems to current systems only, to current plus all advanced systems, or to only the advanced systems that were identified as being attractive on the basis of previous screenings. Further insight can be obtained by examining differences in results between match-heat and match-power strategies or between strategies that allow the export of electricity. The national energy, cost, and emissions saving data presented in this section have been developed by using the approach just described.

Potential national energy savings are presented in figures 6.4-1 to 6.4-6 for three variations of the basic approach: (1) that all of the advanced and current cogeneration systems were available for selection; (2) that only the

previously identified "attractive" advanced systems and all of the current systems were available; and (3) that only current systems were available. For each approach the results shown were obtained by adding the national energy savings in 1990 for each process using the cogeneration system, current or advanced, that had the highest fuel energy saving in that process, according to the procedure previously described. Two further constraints were imposed on the selection process. The cases selected could not export electricity from the plant, and there could be no area-wide emissions increases over those for the noncogeneration operation. In other words the sum of the emissions from the plant site and the utility site in the cogeneration case must be less than in the noncogeneration case.

Three sets of data bars are shown on each plot in figure 6.4-1. The data for the first set were selected from those systems that show only a positive return on investment for the particular application. For the second and third sets the systems were required to have at least 10 or 20 percent return on investment, respectively, in order to be available for selection for a given industry. Each set consists of three bars. For the bottom bar all current and advanced systems were available for selection. For the middle bar only those identified as the overall "attractive" advanced systems and all current systems were available. For the top bar only current systems were available. The availability of the advanced systems resulted in fuel energy savings more than 40 percent higher than with the current systems alone for the GE-based results and fuel energy savings of approximately 80 percent to nearly 400 times higher for the UTC-based results. The middle bars in figure 6.4-1 demonstrate the effects of restricting the set of available systems to those previously identified as attractive advanced plus current. Even with the restricted set of advanced energy conversion systems, the fuel energy savings are still approximately 95 percent of those achievable by choosing from the full set of systems.

The major differences between the contractors' results shown in figure 6.4-1 were in the economics of the current cogeneration systems. The GE current residual-fueled steam turbine is an extremely attractive system with high return-on-investment applications in many industries. As a consequence, for ROI equal to or greater than zero, 17 of the 35 industrial cogeneration system applications in figure 6.4-1(a) are current steam turbine systems; in figure 6.4-1(b) all of the systems are advanced steam turbine systems. The same proportional representation of current steam turbine systems persists throughout the GE data. The emissions savings if advanced systems were available are compared in figure 6.4-2 with the emission savings if only current-technology systems are used. The results are for the same cases selected in the fuel energy saving comparisons made in figure 6.4-1. The GE results showing emission saving increases from approximately 20 percent to more than 50 percent when the advanced systems are assumed to be available. The UTC-based results show emissions saving increases from approximately 20 percent to more than 400 percent higher with the availability of advanced systems. The differences between emissions savings based on the contractors' results have a variety of causes. Chief among them are the differences in the current residual-fueled steam turbine, as discussed previously. Other causes for the differences are the market size of the particular process in which each system produces maximum savings and the differences in assumptions for technological advances, particularly those relating to emissions reductions. Both GE and UTC results show the potential for significant energy savings and area-wide (umbrella) emissions reductions when advanced systems are included in the mix

of available systems. Figure 6.4-3 presents the cost savings for the industry/conversion system combinations shown in the previous two figures.

Recall that figures 6.4-1 to 6.4-3 illustrate the potential savings from a national perspective with the constraint of no export of electricity to the utility grid. Even larger savings with advanced cogeneration systems can be shown when the opportunity to export electricity is allowed since the utility electricity is being displaced by cogenerated electricity that is produced with higher fuel energy efficiency and lower emissions. An example of this is shown in figures 6.4-4 to 6.4-6. Here the national savings for the match-heat strategy are presented. The data were developed by using the same methodology as for figures 6.4-1 to 6.4-3.

From the viewpoint of a potential industrial owner, plant-basis savings are, of course, more important than these national-basis results. Many factors would be important including the system economics, the plant siting emissions, and the type of fuel required for the cogeneration systems. On the basis of ROI alone the advanced systems show benefits over current systems in most applications. Superior energy savings and, in many cases lower capital costs, and annual energy cost reductions are shown for the advanced systems in many applications. Any plant-siting emissions reduction resulting from the use of advanced technology as compared with current technology would be of a major benefit to the plant manager and to society as a whole. In fact, for a few of the advanced cases, plant-siting emissions were even lower than those emissions for the onsite, liquid-fueled noncogeneration boiler. These were predominantly cases where distillate fuels were used with fuel cell systems. Finally, of concern to a potential industrial owner is the type of fuel used to provide heat and electricity for industrial plants. The industrialist is concerned about the dependence on oil from the standpoints of assured availability and cost. The ability to supplant the 20 percent of U.S. oil consumption used by industry is, of course, crucial to our nation. In this study a strong emphasis was placed on advanced cogeneration systems that permit economically and environmentally acceptable use of coal, minimally processed coal-derived liquid fuels, and low- or intermediate-Btu gas made from coal.

The applicability of the most attractive advanced systems to the 10 highest oil-consuming industries studied by both contractors is shown in table 6.4-2. The applications were selected from those identified as attractive in tables 6.3-3 to 6.3-7. The widespread applicability of these advanced conversion systems to the major oil-consuming industries is evident from table 6.4-1.

TABLE 6.1-1 - RESULTS FOR MOST ATTRACTIVE SYSTEMS

(a) Steam turbine/AFB (GE only - UTC system did not achieve attractive results.)

Industry	Energy conversion system sizing strategy	Fuel energy saving ratio, percent	Emissions saving ratio, percent	Levelized annual energy cost saving ratio, percent	Return on investment, percent
Petroleum	Export power	18.1	28	40.3	54
Alumina	Export power	15.1	25	37.4	49
Malt beverages	Match power	24	33	25	17
Writing paper	Import power	28.6	37	41.2	46

(b) Steam turbine/PFB (Only studied by GE.)

Petroleum	Export power	25.8	34	41.5	39
Alumina	Export power	23.5	41	33.2	39
Writing paper	Export power	36.1	51	40.1	27
Newsprint	Import power	19.7	32	21.1	18
Steel	Import power	11.2	16	12	23

(c) Gas turbine/AFB (Only studied by UTC.)

Petroleum	Export power	22.9	29.9	32.3	17.3
Writing paper	Match power	44.3	53.6	37.6	18

(d) Gas turbine/PFB (Only studied by UTC.)

Petroleum	Export power	30.1	42.4	37.2	17.6
Malt beverages	Match power	13.0	23.5	19.0	29.4
Newsprint	Import power	33.7	49.7	30.5	19
Chlorine	Import power	22.7	32.3	23.0	20

(e) Gas turbine/integrated gasifier (Only studied by UTC.)

Writing paper	Import power	20.3	35.7	30.2	19

(f) Closed-cycle gas turbine/AFB (UTC only - GE system did not achieve attractive results.)

Writing paper	Match power	37.6	48	35.2	18
Newsprint	Import power	26.9	38	28.3	20

(g) Molten carbonate fuel cell/gasifier

GE					
Petroleum	Export power	33.5	99.2	33.2	14
Alumina	Export power	33.5	99.1	26.4	11
Newsprint	Export power	33.6	99.7	18.8	11
Chlorine	Import power	29.6	72	22.7	15
UTC					
Newsprint	Match power	37.8	91.1	30	12.8

TABLE 6.1-1. - Concluded.

Industry	Energy conversion system sizing strategy	Fuel energy saving ratio, percent	Emissions saving ratio, percent,	Levelized annual energy cost saving ratio, percent	Return on investment, percent
(h) Advanced gas turbine/residual					
GE					
Petroleum	Export power	31	12	15	23
Alumina		31	12	13	19
Malt beverages		33.7	16	9	10
Writing paper	↓	31	20	19	30
Newsprint	Import power	29	11	21	30
Steel		14	11	10	28
Nylon		17	8	11	22
Chlorine	↓	15	6	11	37
UTC					
Petroleum	Export power	32	43	15	23
Alumina	Export power	26	41.5	8	19
Malt beverages	Export power	36.8	52.1	12.1	12.9
Writing paper	Match power	30	44	22	38
Meat packing	Match power	27.3	41.1	15.1	18.7
Newsprint	Import power	26	36	19	45
Steel[a]	Match power	51.7	65.7	34	45
Nylon	Import power	26	35	18	29
Chlorine	Import power	29	35	23	50
(i) Advanced combined cycle/residual					
GE					
Writing paper	Match power	25	24	16	28
Newsprint	Match power	32	17	19	22
Steel	Import power	18	13	12	25
Nylon	Import power	30	17	15	17
Chlorine	Import power	29	16	21	29
UTC					
Writing paper	Match power	23	38.6	13	21
Newsprint	Match power	34	51.7	23	28
Steel[a]	Match power	44.8	60.8	26	27
Chlorine	Import power	38	53.2	27	31
(j) Molten carbonate fuel cell/distillate (UTC only - GE system did not achieve attractive results.)					
Writing paper	Match power	34	67	14	20
Steel[a]	Match power	57.3	85.2	25	19
Nylon	Import power	36	72	11	14
Chlorine	Match power	41	79	15	16

[a]Includes use of byproduct fuel in the energy conversion system.

TABLE 6.1-2 - COMPARISON OF GE RESULTS FOR MOST ATTRACTIVE APPLICATIONS OF OTHER ADVANCED SYSTEMS WITH RESULTS IN SAME INDUSTRIES FOR ADVANCED SYSTEMS SELECTED BY LEWIS SCREENING APPROACH

[All values relative to noncogeneration boiler burning residual-grade, coal-derived liquid fuels and coal-fired utility.]

(a) Results for most attractive application of other advanced systems

System	Most attractive application	Return on investment, percent	Fuel energy saving ratio, percent
Diesel (residual-grade, coal-derived liquid fuels)	Chlorine	14.7	21.7
Stirling engine (coal with flue gas desulfurization)	Petroleum refining	18.7	11.5
Closed-cycle gas turbine/AFB (coal fired)	Integrated chemical	15.0	11.0
Thermionics - steam (coal with flue gas desulfurization)	Petroleum refining	15.3	16.7
Phosphoric acid fuel cells (distillate-grade, coal-derived liquid fuels	Malt beverages	(a)	20.0
Molten carbonate fuel cells (distillate-grade, coal-derived liquid fuels)	Chlorine	(a)	35.0

(b) Results in same industries for advanced systems selected by Lewis screening approach

Industry	System	Return on investment, percent	Fuel energy saving ratio, percent
Chlorine	Combined cycle (residual-grade, coal-derived liquid fuels)	31.2	29.5
Petroleum refining	Steam turbine/AFB	50+	18.9
Integrated chemical	Steam turbine/PFB	41.0	27.4
Malt beverages	Advanced gas turbine (residual-grade, coal-derived liquid fuels)	12.0	31.0

TABLE 6.1-3 - COMPARISON OF UTC RESULTS FOR MOST ATTRACTIVE APPLICATIONS OF OTHER ADVANCED SYSTEMS WITH RESULTS IN SAME INDUSTRIES FOR ADVANCED SYSTEMS SELECTED BY LEWIS SCREENING APPROACH

[All values relative to noncogeneration boiler burning residual-grade, coal-derived liquid fuels and coal-fired utility.]

(a) Results for most attractive application of other advanced systems

System	Most attractive application	Return on investment, percent	Fuel energy saving ratio, percent
Low-speed diesel (residual-grade, coal-derived liquid fuels)	Corrugated paper	10.5	20.4
High-speed diesel (distillate-grade, coal-derived liquid fuels)	Chlorine	11.5	47.6
Stirling engine (residual-grade, coal-derived liquid fuels)	Boxboard	11.0	22.0
Stirling engine/AFB (coal fired)	Corrugated paper	24.3	16.6
Thermionics (residual-grade, coal-grade, coal-derived liquid fuels	Corrugated paper	9.9	24.3
Phosphoric acid fuel cell (distillate-grade, coal-derived liquid fuels)	Boxboard	14.0	31.0

(b) Results in same industries for advanced systems selected by Lewis screening approach

Industry	System	Return on investment, percent	Fuel energy saving ratio, percent
Corrugated paper	Advanced gas turbine (residual-grade, coal-derived liquid fuels)	30.3	37.3
Corrugated paper	Steam turbine/AFB	37.0	43.0
Chlorine	Advanced gas turbine (residual-grade, coal-derived liquid fuels)	41.0	27.4
Boxboard	Advanced gas turbine (residual-grade, coal-derived liquid fuels)	34.8	37.2

TABLE 6.3-1 - RANGES OF RESULTS FOR ATTRACTIVE PROCESSES - NO EXPORT OF ELECTRICITY ALLOWED

[All values relative to noncogeneration boiler burning residual-grade, coal-derived liquid fuels and coal-fired utility. Heavy box includes cases with ROI ≥20 percent and fuel energy savings ≥10 percent.]

(a) Advanced systems using coal

System	Contractor	Industry									
		Foods		Paper		Chemicals		Petroleum		Metals	
		Return on invest-ment, percent	Fuel energy saving ratio, percent	Return on invest-ment, percent	Fuel energy saving ratio, percent	Return on invest-ment, percent	Fuel energy saving ratio, percent	Return on invest-ment, percent	Fuel energy saving ratio, percent	Return on invest-ment, percent	Fuel energy saving ratio, percent
Steam turbine/AFB	GE	10-29	18-24	26-50+	12-29	39-50+	13-16	33-50+	16-17	40	6
	UTC	9	20-40	22-46	50+	50+	8	------	-----	-----	-----
Steam turbine/PFB	GE	20	17	19-22	20-30	25-42	13-26	19-41	15-17	24	11
Gas turbine/AFB	UTC	9	13	18-20	35-44	-----	-----	42	6	-----	-----
Gas turbine/PFB	UTC	6-11	13-21	17-24	21-32	13	15	50+	5	12	20
Gas turbine/integrated gasifier	UTC	7-8	13-20	19-22	20-33	-----	-----	------	-----	-----	-----
Closed-cycle gas	GE	-----	-----	-----	-----	-----	-----	------	-----	-----	-----
turbine/AFB	UTC	8-9	10-25	17-26	22-38	50+	9	50+	3	-----	-----
Molten carbonate fuel	GE	12	16	9-11	21-34	15-16	12-30	15	20	12	21
cell/gasifier	UTC	5	10-26	11-15	23-38	-----	-----	------	-----	-----	-----

(b) Advanced systems using coal-derived liquid fuels

System	Contractor	Foods ROI	Foods FESR	Paper ROI	Paper FESR	Chemicals ROI	Chemicals FESR	Petroleum ROI	Petroleum FESR	Metals ROI	Metals FESR
Gas turbine/	GE	20-22	10-15	17-35	19-32	20-37	11-32	17-38	13-14	21-29	13-28
residual	UTC	18-22	11-17	32-50+	24-30	22-41	10-38	14	7	25-44	5-30
Combined cycle/	GE	6-18	14-19	20-28	18-30	17-31	10-30	14-29	12-13	18-25	17-35
residual	UTC	6	21	21-28	20-34	13-31	29-39	-----	-----	12-27	5-29
Molten carbonate fuel	GE	-----	-----	------	-----	-----	-----	-----	-----	-----	-----
cell/distillate	UTC	9	31	20	26-34	12-15	37-41	13	7	13-19	6-25

TABLE 6.3-2 - RANGES OF RESULTS FOR ATTRACTIVE PROCESSES - EXPORT OF ELECTRICITY ALLOWED

[All values relative to noncogeneration boiler burning residual-grade, coal-derived liquid fuels and coal-fired utility. Heavy box includes cases with ROI ≥20 percent and fuel energy savings ≥10 percent.]

(a) Advanced systems using coal

System	Contractor	Industry									
		Foods		Paper		Chemicals		Petroleum		Metals	
		Return on invest-ment, percent	Fuel energy saving ratio, percent	Return on invest-ment, percent	Fuel energy saving ratio, percent	Return on invest-ment, percent	Fuel energy saving ratio, percent	Return on invest-ment, percent	Fuel energy saving ratio, percent	Return on invest-ment, percent	Fuel energy saving ratio, percent
Steam turbine/AFB	GE	12-38	28-32	33-50+	20-30	24-50+	15-32	19	23	40	6
	UTC	7	12	14-25	22-46	27-50	7-8	------	-----	-----	-----
Steam turbine/PFB	GE	9-23	33	18-27	20-36	15-42	24-38	10	29	24	11
Gas turbine/AFB	UTC	-----	-----	17-20	19-44	9-20	-6-13	17	23	21	20
Gas turbine/PFB	UTC	5	23-26	17-18	28-34	7-46	4-23	18	30	12-22	8-21
Gas turbine/integrated gasifier	UTC	7-9	21-23	21-22	22-33	9-23	6-21	16	27	15	21
Closed-cycle gas	GE	-----	-----	-----	-----	-----	-----	------	-----	-----	-----
turbine/AFB	UTC	7	28	19-25	27-38	18-49	3-16	45	4	-----	-----
Molten carbonate fuel	GE	8	42	8-9	33-40	15	30-38	2	40	7-12	21-39
cell/gasifier	UTC	-----	-----	10-13	27-38	13	25	------	-----	7	23

(b) Advanced systems using coal-derived liquid fuels

System	Contractor	Foods ROI	Foods FESR	Paper ROI	Paper FESR	Chemicals ROI	Chemicals FESR	Petroleum ROI	Petroleum FESR	Metals ROI	Metals FESR
Gas turbine/	GE	11-16	34	15-27	33	10-37	21-34	17-22	33	20-29	13-28
residual	UTC	13	37	31-36	27-37	33-37	32-37	23	32	25-29	21-38
Combined cycle/	GE	-----	-----	12-17	36-37	10-31	23-37	10-13	35-36	17-25	18-36
residual	UTC	-----	-----	8-27	35	13-31	18-39	13	27	10	31
Molten carbonate fuel	GE	-----	-----	------	-----	-----	-----	-----	-----	-----	-----
cell/distillate	UTC	-----	-----	9-10	33-43	12-41	37-41	-----	-----	-----	-----

TABLE 6.3-3 - SYSTEM APPLICABILITY - FOOD INDUSTRY

[X indicates attractive results; dashes indicate that system was studied but not found attractive.]

(a) Advanced systems using coal

System	Contractor	Attractive application if no export of electricity is allowed				Attractive application if export of electricity is allowed			
		Malt beverage	Meat packing	Wet corn milling	Others	Malt beverage	Meat packing	Wet corn milling	Others
Steam turbine/AFB	GE	X	---	X[a]	---	X	---	X[a]	X
	UTC	X	---	(b)	---	X	---	(b)	---
Steam turbine/PFB	GE	---	---	X[a]	---	X	---	X[a]	---
Gas turbine/AFB	UTC	X	---	(b)	---	---	---	(b)	---
Gas turbine/PFB	UTC	X	X	(b)	---	X	X	(b)	---
Gas turbine/integrated gasifier	UTC	X	X	(b)	---	X	X	(b)	---
Closed-cycle gas turbine/AFB	GE	---	---	---	---	---	---	---	---
	UTC	X	X	(b)	---	---	X	(b)	---
Molton carbonate fuel cell/ integrated gasifier	GE	---	---	X	---	---	---	X	---
	UTC	X	X	(b)	---	---	---	(b)	---

(b) Advanced systems using coal-derived liquid fuels

System	Contractor	Malt beverage	Meat packing	Wet corn milling	Others	Malt beverage	Meat packing	Wet corn milling	Others
Gas turbine/residual	GE	X[a]	---	X[a]	---	X	---	X	---
	UTC	X[a]	X	(b)	---	X	X	(b)	---
Combined cycle/residual	GE	---	X	X	---	---	---	---	---
	UTC	---	X	(b)	---	---	---	(b)	---
Molten carbonate fuel cell/ distillate	GE	---	---	---	---	---	---	---	---
	UTC	---	X	(b)	---	---	---	(b)	---

[a]Results with ROI ≥ 20 percent and fuel energy savings ≥ 10 percent relative to noncogeneration boiler buring residual-grade, coal-derived liquid fuels and coal-fired utility.
[b]Not studied.

TABLE 6.3-4 - SYSTEM APPLICABILITY - PAPER INDUSTRY

[X indicates attractive results; dashes indicate that system was studied but not found attractive.]

(a) Advanced systems using coal

System	Contractor	Attractive application if no export of electricity is allowed					Attractive application if export of electricity is allowed				
		Writing paper	Corru- gated paper	Box- board	News- print	Others	Writing paper	Corru- gated paper	Box- board	News- print	Others
Steam turbine/AFB	GE	X[a]	X[a]	X[a]	X[a]	X[a]	X[a]	X[a]	X[a]	----	X[a]
	UTC	X[a]	X[a]	X[a]	----	----	X	X[a]	X[a]	----	----
Steam turbine/PFB	GE	X[a]	X	X	X	----	X[a]	X[a]	X[a]	X	----
Gas turbine/AFB	UTC	X	X	X[a]	----	----	X	X	X[a]	X	----
Gas turbine/PFB	UTC	X	X[a]	X[a]	X	----	X	X	X	X	----
Gas turbine/integrated gasifier	UTC	X	X[a]	X[a]	----	----	X[a]	X[a]	X[a]	X[a]	----
Closed-cycle gas turbine/ AFB	GE	----	----	----	----	----	----	----	----	----	----
	UTC	X	X[a]	X[a]	X	----	X	X[a]	X[a]	X[a]	----
Molten carbonate fuel cell/	GE	----	X	----	X	----	X	X	----	X	X

(b) Advanced systems using coal-derived liquid fuels

System	Contractor	Writing paper	Corru- gated paper	Box- board	News- print	Others	Writing paper	Corru- gated paper	Box- board	News- print	Others
Gas turbine/residual	GE	X[a]	X[a]	X[a]	X[a]	X	X[a]	X[a]	X[a]	X[a]	X
	UTC	X[a]	X[a]	X[a]	X[a]	----	X[a]	X[a]	X[a]	X[a]	----
Combined cycle/residual	GE	X[a]	X[a]	X[a]	X[a]	----	X	X	X	X	----
Molten carbonate fuel cell/ distillate	GE	----	----	----	----	----	----	----	----	----	----
	UTC	X[a]	X[a]	X[a]	----	----	X	----	X	X	----

[a]Results with ROI 20 percent and fuel energy savings 10 percent relative to noncogeneration boiler burning residual-grade, coal-derived liquid fuels and coal-fired utility.

TABLE 6.3-5 - SYSTEM APPLICABILITY - CHEMICAL INDUSTRY

[X indicates attractive results; dashes indicate that system was studied but not found attractive.]

(a) Advanced systems using coal

System	Contractor	Attractive application if no export of electricity is allowed					Attractive application if export of electricity is allowed				
		Alumina	Styrene	Ethylene	Chlorine	Others	Alumina	Styrene	Ethylene	Chlorine	Others
Steam turbine/AFB	GE	X[a]	----	----	----	X[a]	X[a]	X[a]	----	----	X[a]
	UTC	----	----	----	----	X	----	X	X	X	----
Steam turbine/PFB	GE	X[a]	----	----	----	X[a]	X[a]	X	----	----	X[a]
Gas turbine/AFB	UTC	----	----	----	----	----	----	X[a]	X	X[a]	----
Gas turbine/PFB	UTC	----	----	----	X	----	----	X[a]	X	X[a]	X
Gas turbine/integrated gasifier	UTC	----	----	----	----	----	----	----	----	X[a]	X
Closed-cycle gas turbine/ AFB	GE	----	----	----	----	----	----	----	----	----	----
	UTC	----	----	----	----	X	----	X	X	X	----
Molten carbonate fuel cell/ integrated gasifier	GE	----	----	----	X	X	X	----	----	X	----
	UTC	----	----	----	----	----	----	----	----	X	----

(b) Advanced systems using coal-derived liquid fuels

System	Contractor	Attractive application if no export of electricity is allowed					Attractive application if export of electricity is allowed				
		Alumina	Styrene butadiene	Chlorine	Nylon	Others	Alumina	Styrene butadiene	Chlorine	Nylon	Others
Steam turbine/residual	GE	X[a]	X[a]	X[a]	X[a]	X[a]	X	X[a]	X[a]	X[a]	X[a]
	UTC	X[a]	X[a]	X[a]	X[a]	X[a]	X	X	X[a]	X[a]	X[a]
Combined cycle/residual	GE	X[a]	----	X[a]	X	X[a]	X	X	X[a]	X	X[a]
	UTC	----	----	X[a]	X	X	----	----	X[a]	X	X
Molten carbonate fuel cell/ distillate	GE	----	----	----	----	----	----	----	----	----	----
	UTC	----	----	X	X	X---	----	----	X	X	X

[a]Results with ROI 20 percent and fuel energy savings 10 percent relative to noncogeneration boiler burning residual-grade, coal-derived liquid fuels and coal-fired utility.

TABLE 6.3-6 - SYSTEM APPLICABILITY - PETROLEUM INDUSTRY

[X indicates attractive results; dashes indicate that system was studied but not found attractive.]

(a) Advanced systems using coal

System	Contractor	Attractive application if no export of electricity is allowed	Attractive application if export of electricity is allowed
Steam turbine/AFB	GE	X[a]	X
	UTC	----	----
Steam turbine/PFB	GE	X[a]	X
Gas turbine/AFB	UTC	X	X
Gas turbine/PFB	UTC	X	X
Gas turbine/integrated gasifier	UTC	----	X
Closed-cycle gas turbine/ AFB	GE	X	----
	UTC	----	X
Molten carbonate fuel cell/ integrated gasifier	GE	X	X
	UTC	----	----

(b) Advanced systems using coal-derived liquid fuels

System	Contractor	Attractive application if no export of electricity is allowed	Attractive application if export of electricity is allowed
Gas turbine/residual	GE	X[a]	X[a]
	UTC	X	X[a]
Combined cycle/residual	GE	X[a]	X
	UTC	----	X
Molten carbonate fuel cell/ distillate	GE	----	----
	UTC	X	----

[a]Results with ROI$\geq$20 percent and fuel energy savings$\geq$10 percent relative to noncogeneration boiler burning residual-grade, coal-derived liquid fuels and coal-fired utility.

TABLE 6.3-7 - SYSTEM APPLICABILITY - METALS INDUSTRY

[X indicates attractive results; dashes indicate that system was studied but not found attractive.]

(a) Advanced systems using coal

System	Contractor	Attractive application if no export of electricity is allowed			Attractive application if export of electricity is allowed		
		Integrated steel	Copper	Others	Integrated steel	Copper	Others
Steam turbine/AFB	GE	X	----	----	X	----	----
	UTC	----	----	----	----	----	----
Steam turbine/PFB	GE	X	----	----	X[a]	----	----
Gas turbine/AFB	UTC	----	----	----	----	----	X[a]
Gas turbine/PFB	UTC	----	X	----	----	X	X
Gas turbine/integrated gasifier	UTC	----	----	----	----	X	----
Closed-cycle gas turbine AFB	GE	----	----	----	----	----	----
	UTC	----	----	----	----	----	----
Molten carbonate fuel cell/ integrated gasifier	GE	X	----	----	X	X	X
	UTC	----	----	----	----	X	----

(b) Advanced systems using coal-derived liquid fuels

System	Contractor	Integrated steel	Copper	Others	Integrated steel	Copper	Others
Gas turbine/residual	GE	X[a]	X[a]	X[a]	X[a]	X[a]	X[a]
	UTC	X	X[a]	X[a]	----	X[a]	X[a]
Combined cycle/residual	GE	X[a]	X	X	X[a]	X	X
	UTC	X	X	X[a]	----	X	----
Molten carbonate fuel cell/ distillate	GE	----	----	----	----	----	----
	UTC	X	X	----	----	----	----

[a]Results with ROI≥20 percent and fuel energy savings≥10 percent relative to non-cogeneration boiler burning residual-grade, coal-derived liquid fuels and coal-fired utility.

TABLE 6.4-1 - UNRESTRICTED SELECTION OF ENERGY CONVERSION SYSTEM TYPES

[Data from UTC study; blanks indicate negative FESR or ROI lower than hurdle rate; match-power strategy.]

Industry	Energy conversion system	Best fuel energy saving ratio with 20 percent return on investment	Fuel energy saving, Btu/yr
1			
2			
3	Gas turbine/coal-derived residual	0.1735	1.961×10^{12}
4			
5			
6	Combined cycle	.3403	11.4
7	Gas turbine	.3036	8.895
8	Gas turbine/AFB	.2726	48.04
9	Gas turbine/AFB	.3601	21.48
10	Combined cycle	.3893	59.17
11	Gas turbine	.0989	2.284
12			
13	Gas turbine	.3232	8.66
14	Gas turbine	.3704	16.07
15	Gas turbine	.1514	.572
16	Steam turbine/integrated gasifier	.3044	2.93
17	Closed cycle/AFB	.0094	.455
18			
19	Gas turbine/AFB	.0591	32.98
20	Gas turbine	.2987	4.84
21			
22			
23	Gas turbine	.0533	41.36
24	Combined cycle	.2883	8.476
25	Gas turbine	.3023	11.34
26	Gas turbine	.2633	9.19

TABLE 6.4-2. - APPLICABILITY OF ADVANCED SYSTEMS TO HIGH OIL-CONSUMING INDUSTRIES[a]

[X indicates attractive results; dashes indicate systems were studied but not found attractive.]

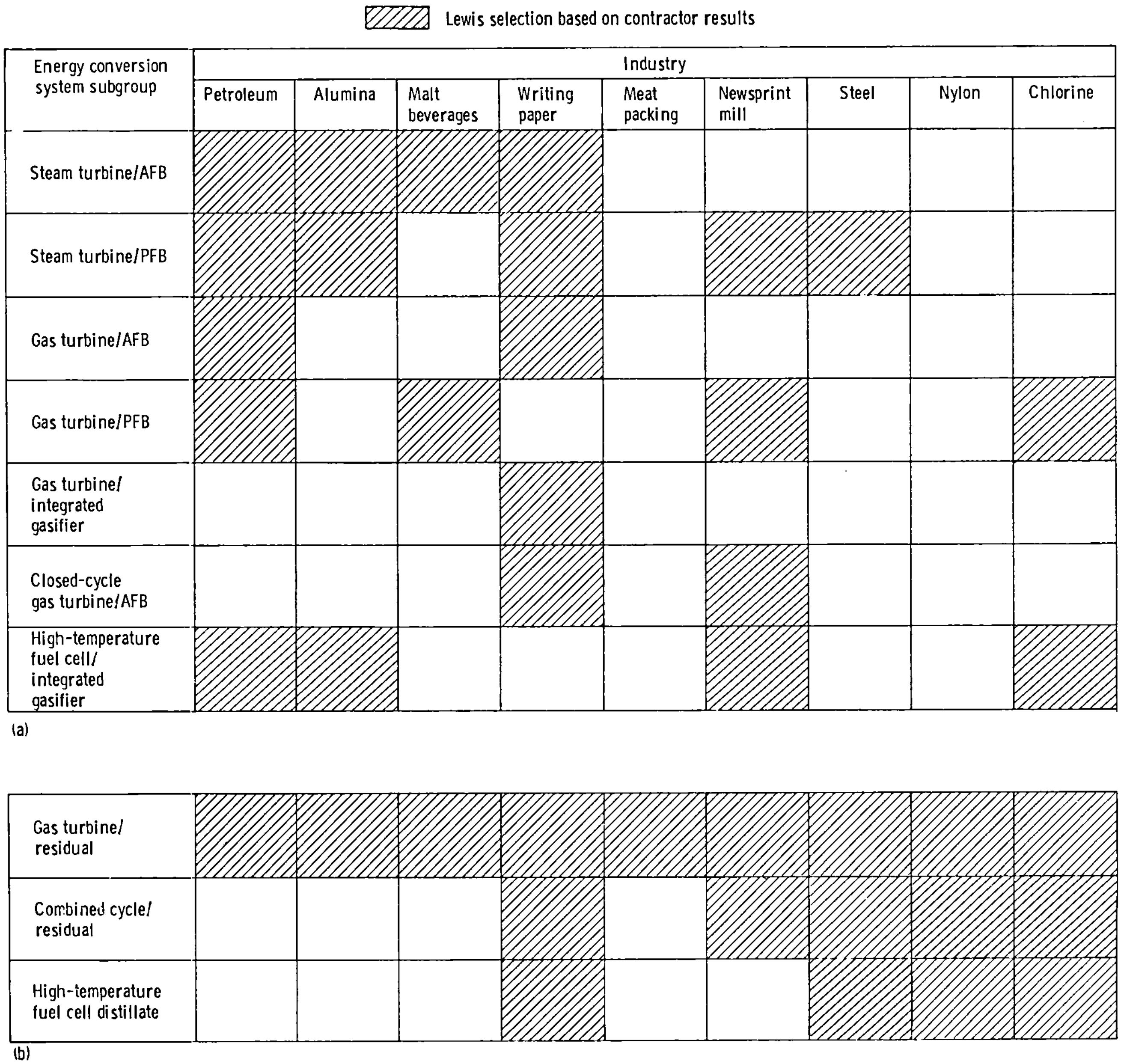
(a) Advanced systems using coal

Industrial process	Projected 1990 annual oil consumption,[b] Btu	System				
		Steam turbine/ PFB	Steam turbine/ PFB	Gas turbine[c]	Closed-cycle gas turbine	Molten carbonate fuel cell with integrated gasifier
Petroleum refining	936×10^{12}	X	X	X	---	X
Integrated steel	299	X	X	X	---	X
Ethylene	251	X	---	X	X	---
Corrugated paper	97	X	X	X	X	---
Styrene	43	X	---	X	X	---
Alumina	38	X	X	---	---	---
Boxboard	28	X	X	X	X	---
Writing paper	23	X	X	X	X	X
Chlorine	21	---	---	X	---	X
Malt beverages	15	X	---	---	---	---

(b) Advanced systems using coal-derived liquid fuels

Industrial process	Projected 1990 annual oil consumption, Btu	System		
		Gas turbine/ residual	Combined cycle/ residual	Molten carbonate fuel cell/ distillate
Petroleum refining	936×10^{12}	X	X	---
Integrated steel	299	X	X	---
Ethylene	251	---	---	---
Corrugated paper	97	X	X	X
Styrene	43	---	---	---
Alumina	38	X	X	---
Boxboard	28	X	X	X
Writing paper	23	X	X	X
Chlorine	21	X	X	X
Malt beverages	15	X	---	---

[a]Noncogeneration consumption for highest oil-consuming industries included in GE and UTC studies.
[b]Taken from Gordian Associates' data prepared as part of UTC contracted study. The estimates were made before enactment of National Energy Act legislation.
[c]AFB, PFB, and integrated-gasifier systems.



(a) Advanced systems using coal.
(b) Advanced systems using coal-derived liquid fuels.

Figure 6. 1-1. - Applicability of selected advanced systems to representative industries.

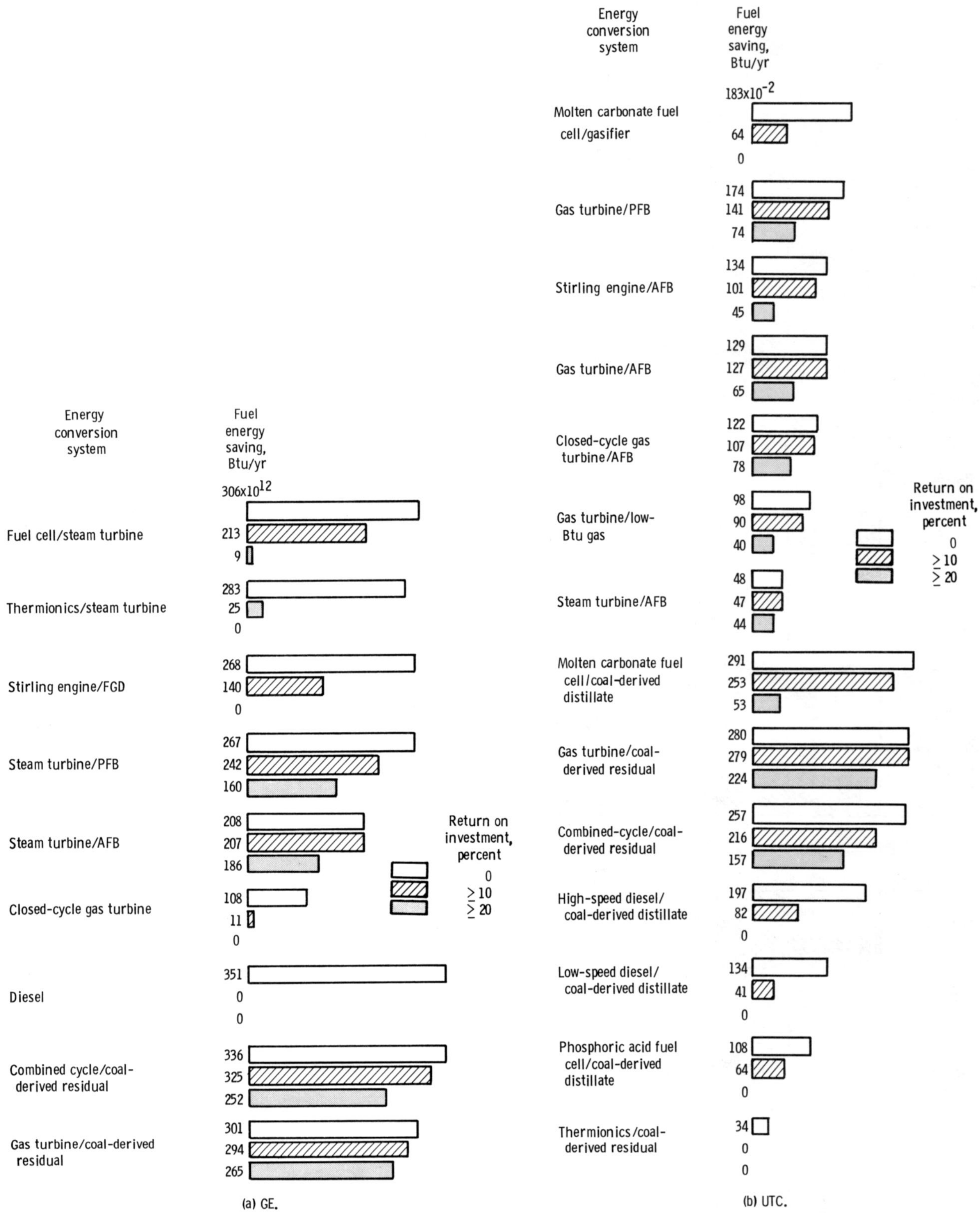
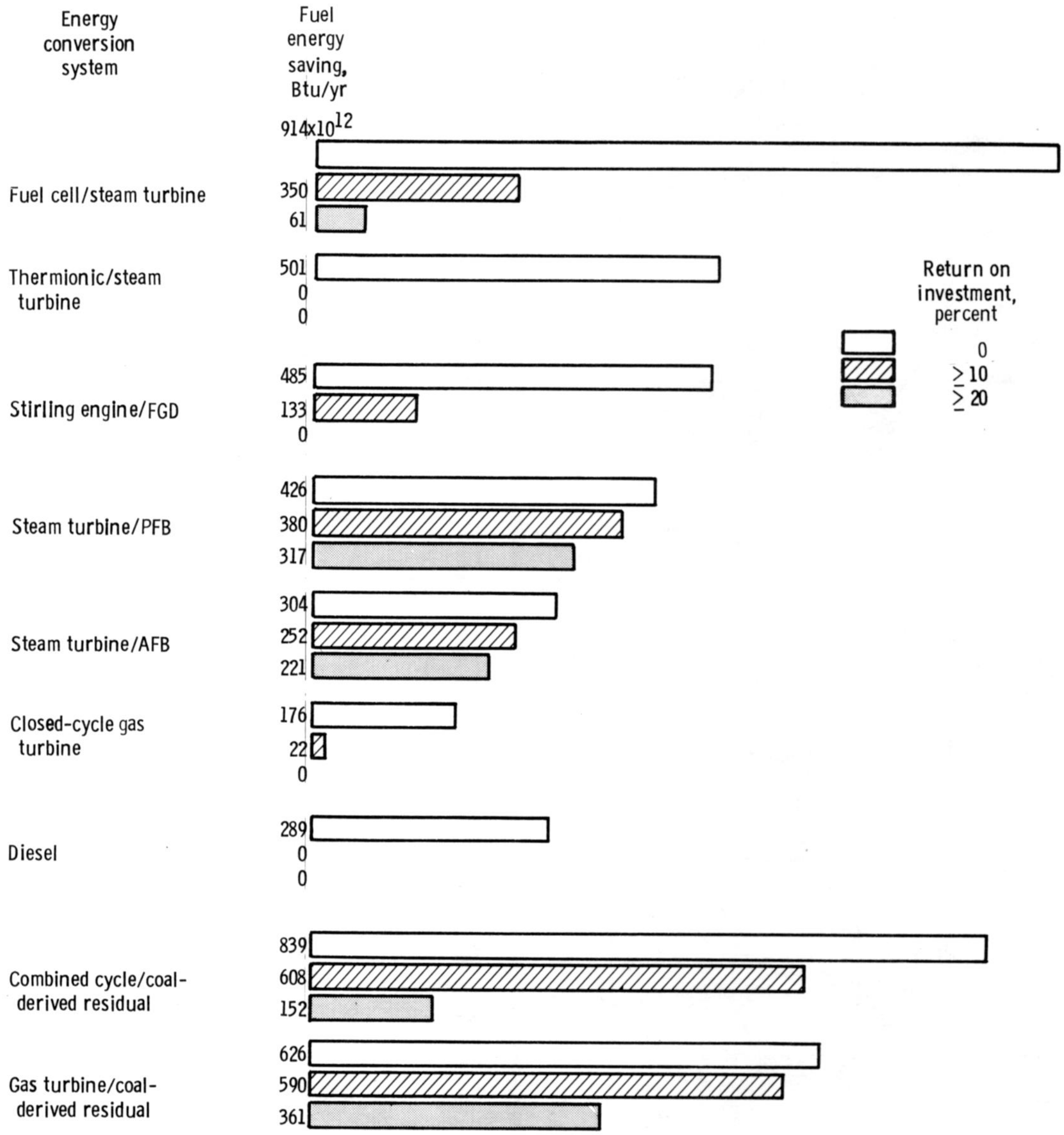
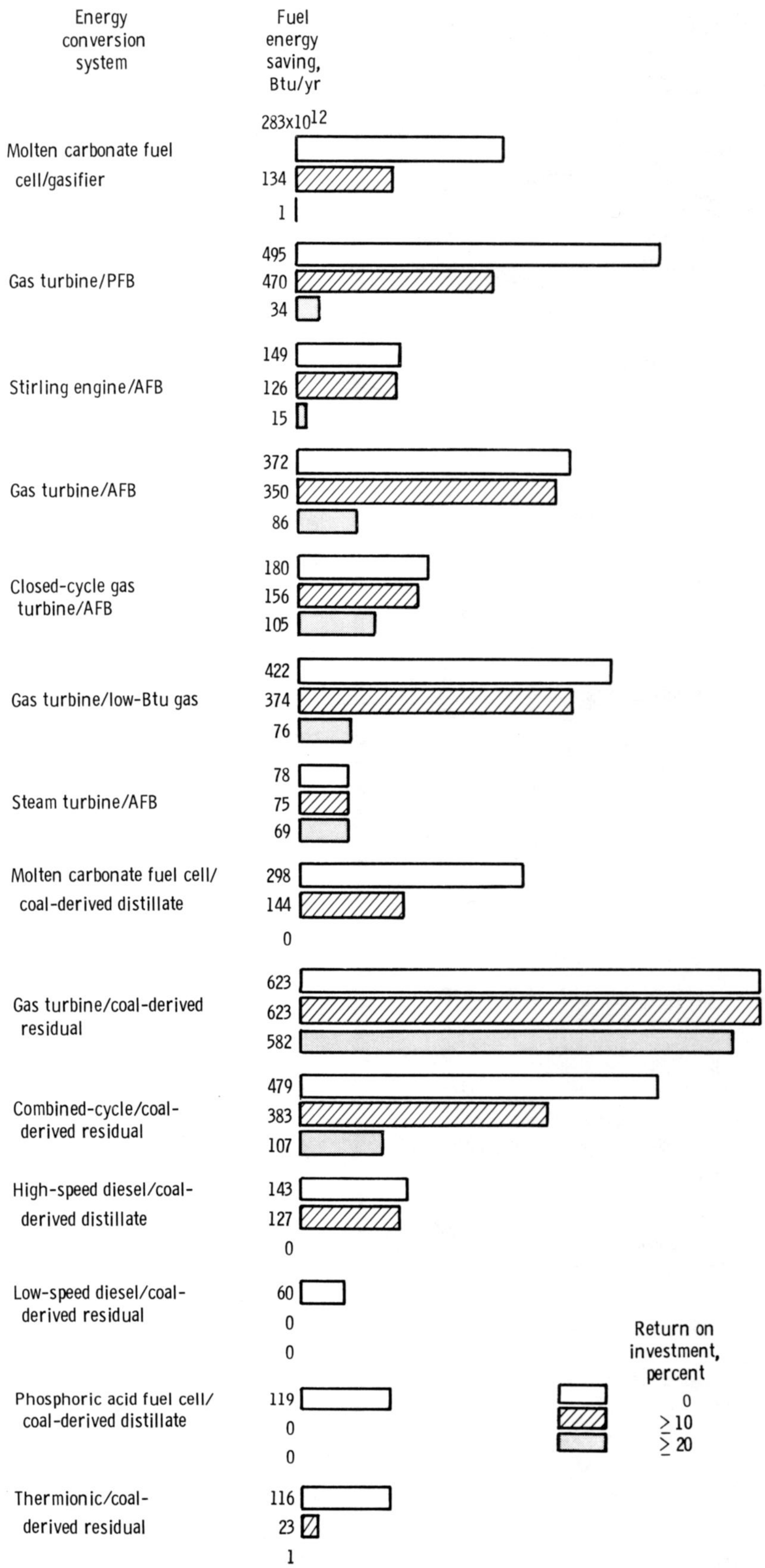


Figure 6.2-1. - Relative fuel energy savings for advanced power systems with no power export allowed.



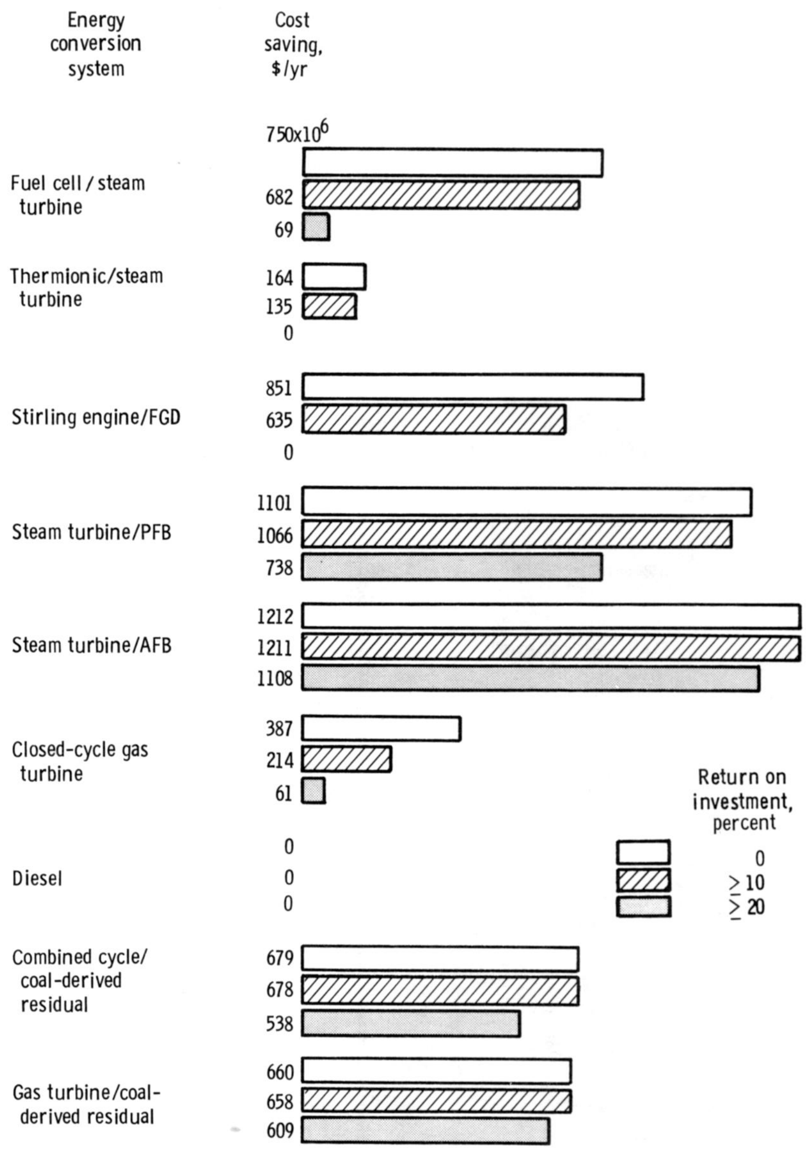
(a) GE.

Figure 6. 2-2. - Relative fuel energy savings for advanced power systems with power export allowed.



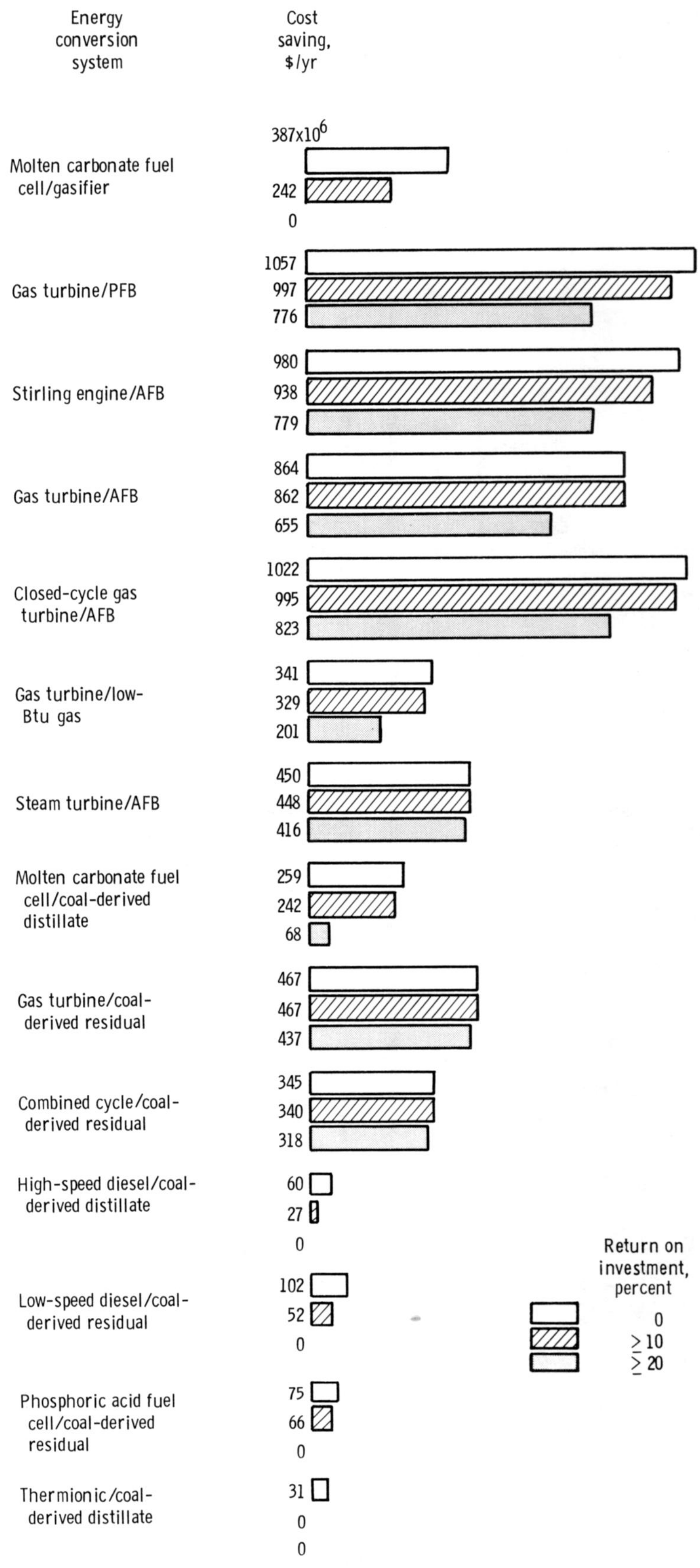
(b) UTC.

Figure 6.2-2. - Concluded.



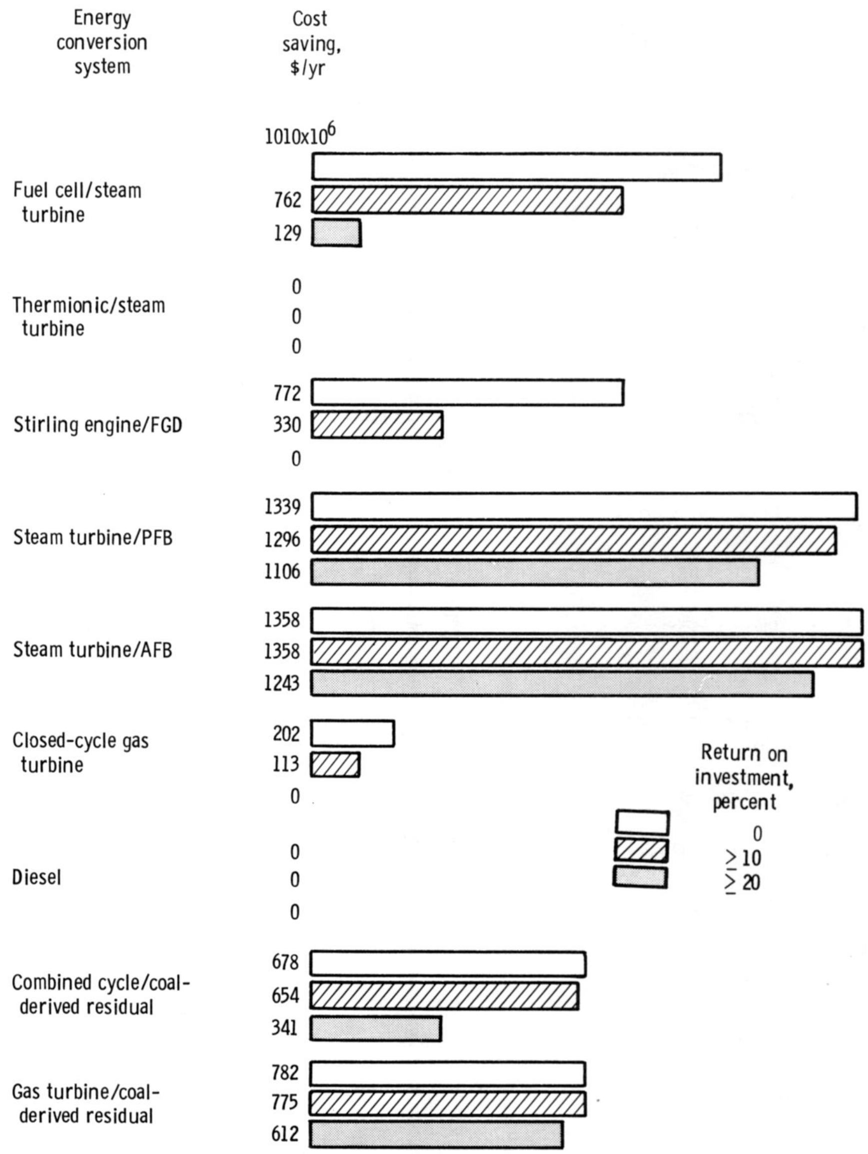
(a) GE.

Figure 6.2-3. - Relative cost savings for advanced power systems with no power export allowed.



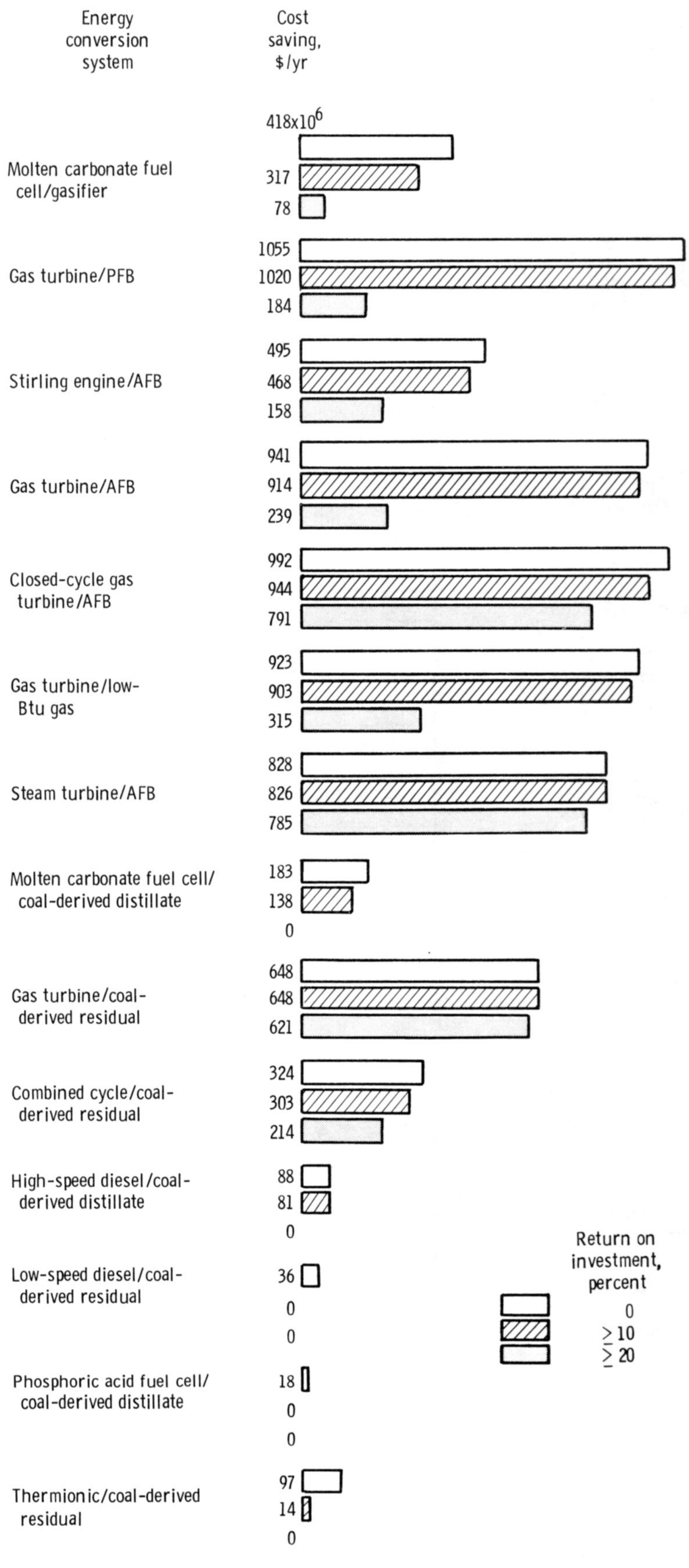
(b) UTC.

Figure 6.2-3. - Concluded.



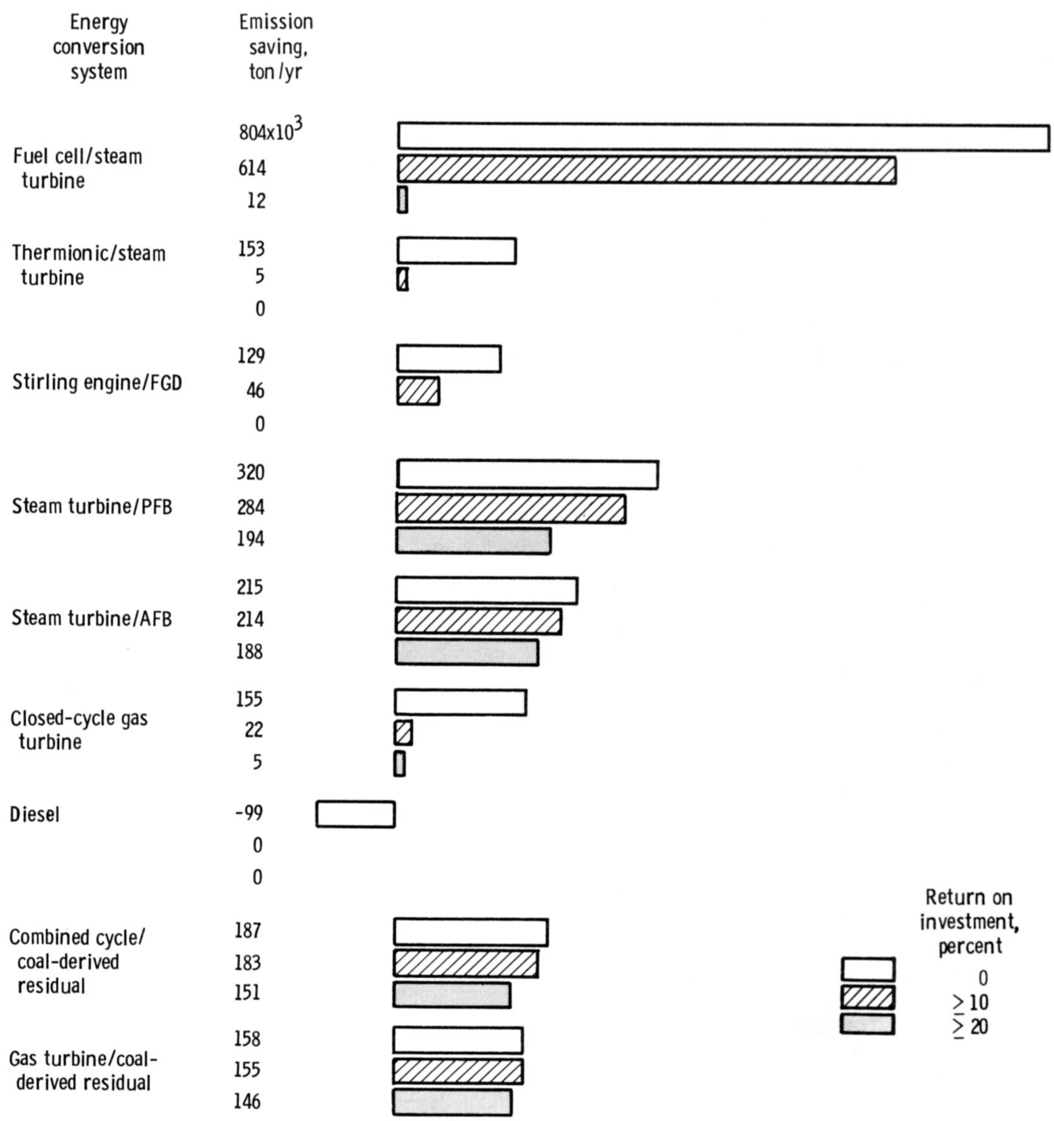
(a) GE.

Figure 6.2-4. - Relative cost savings for advanced power systems with power export allowed.



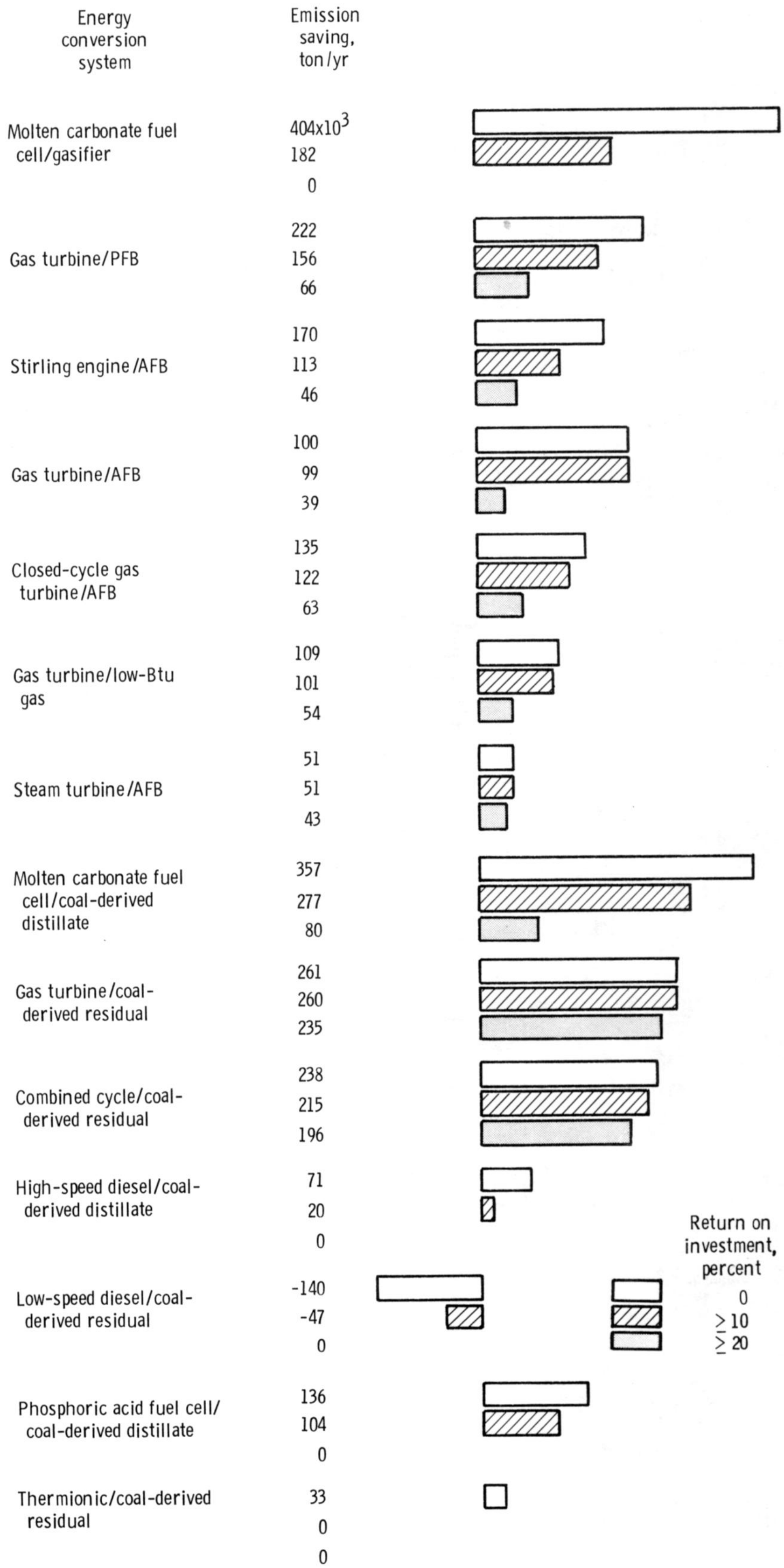
(b) UTC.

Figure 6.2-4. - Concluded.



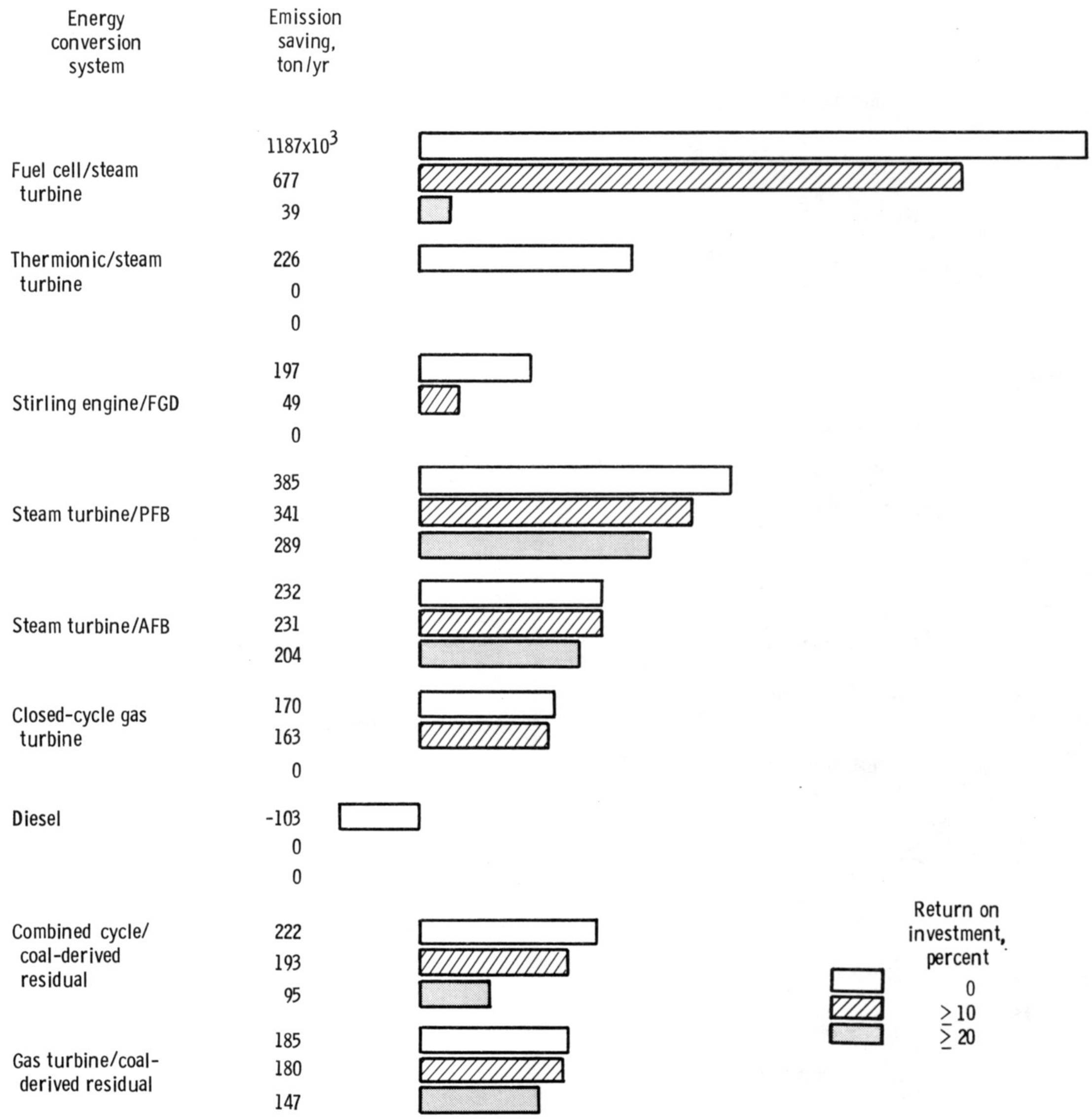
(a) GE.

Figure 6.2-5. - Relative emissions savings for advanced power systems with no power export allowed.



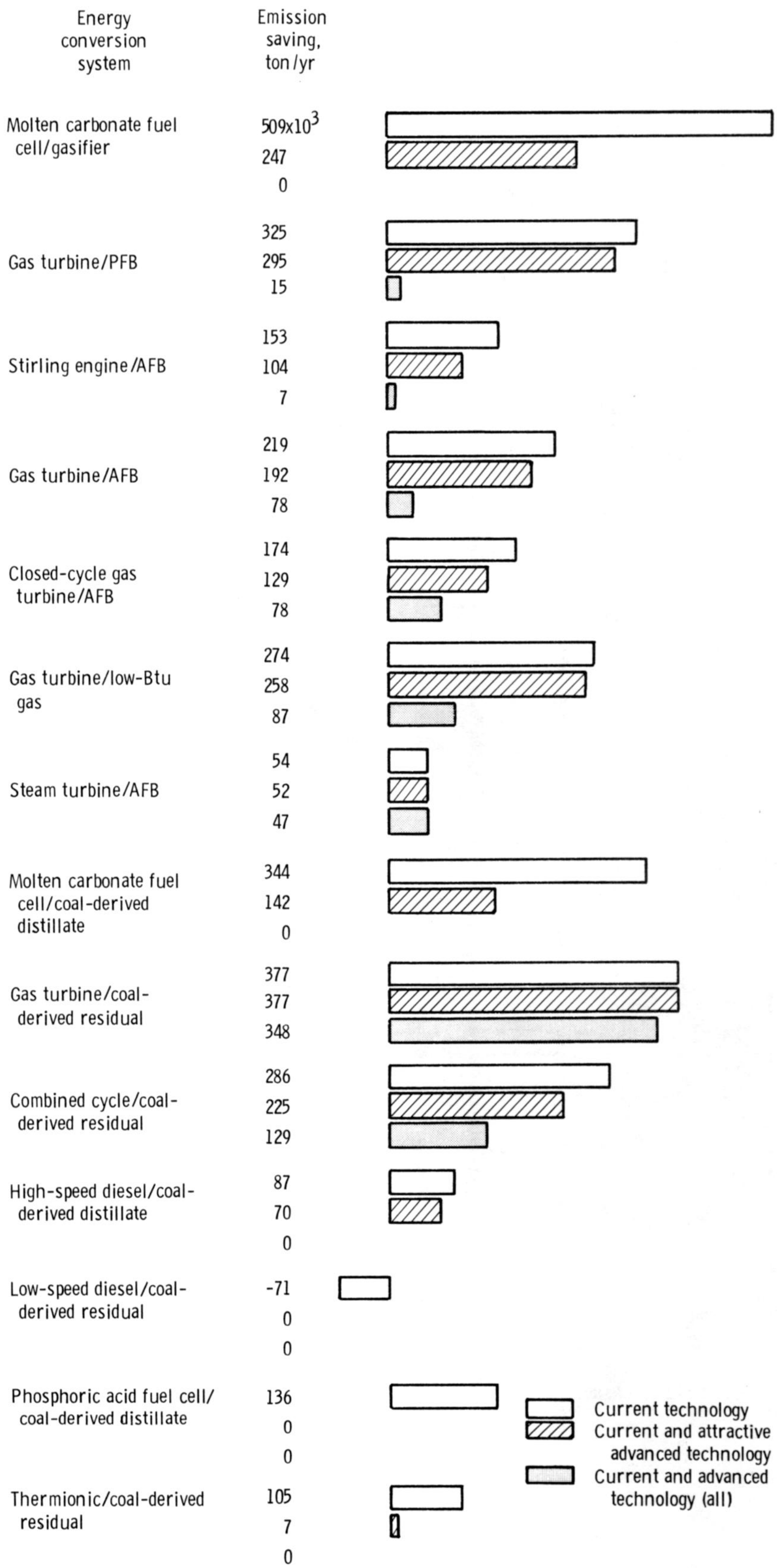
(b) UTC.

Figure 6.2-5. - Concluded.



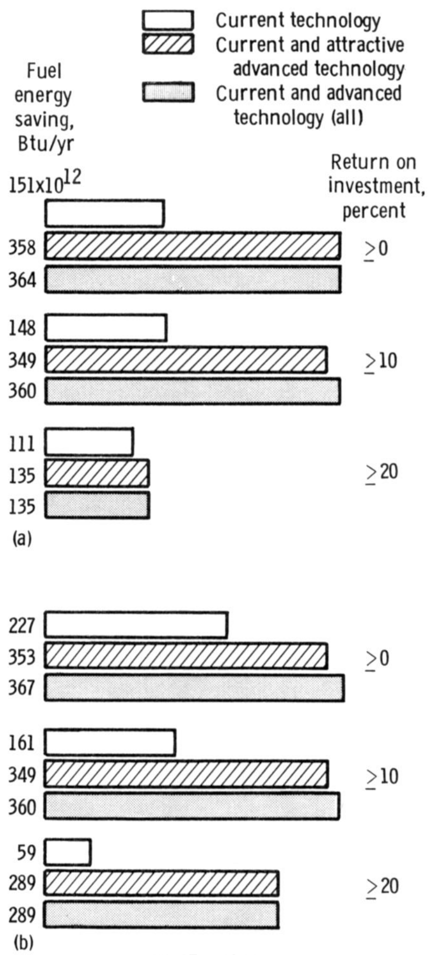
(a) GE.

Figure 6.2-6. - Relative emissions savings for advanced power systems with power export allowed.



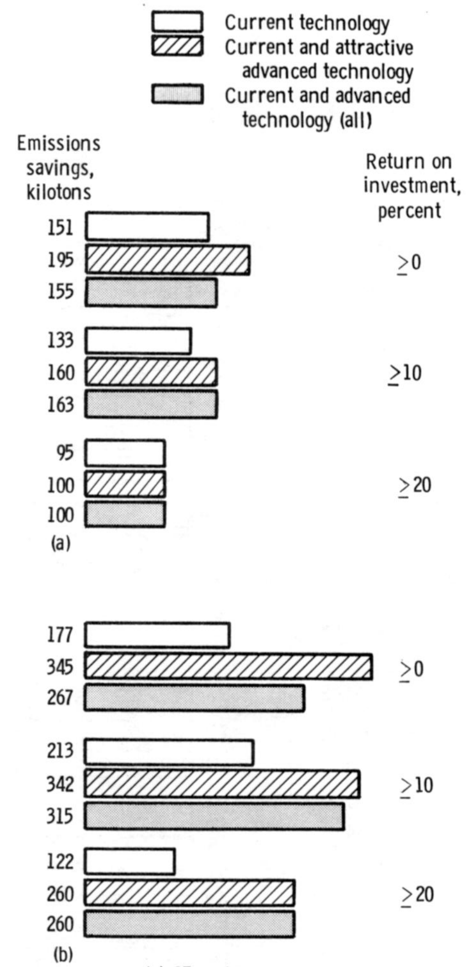
(b) UTC.

Figure 6.2-6. - Concluded.



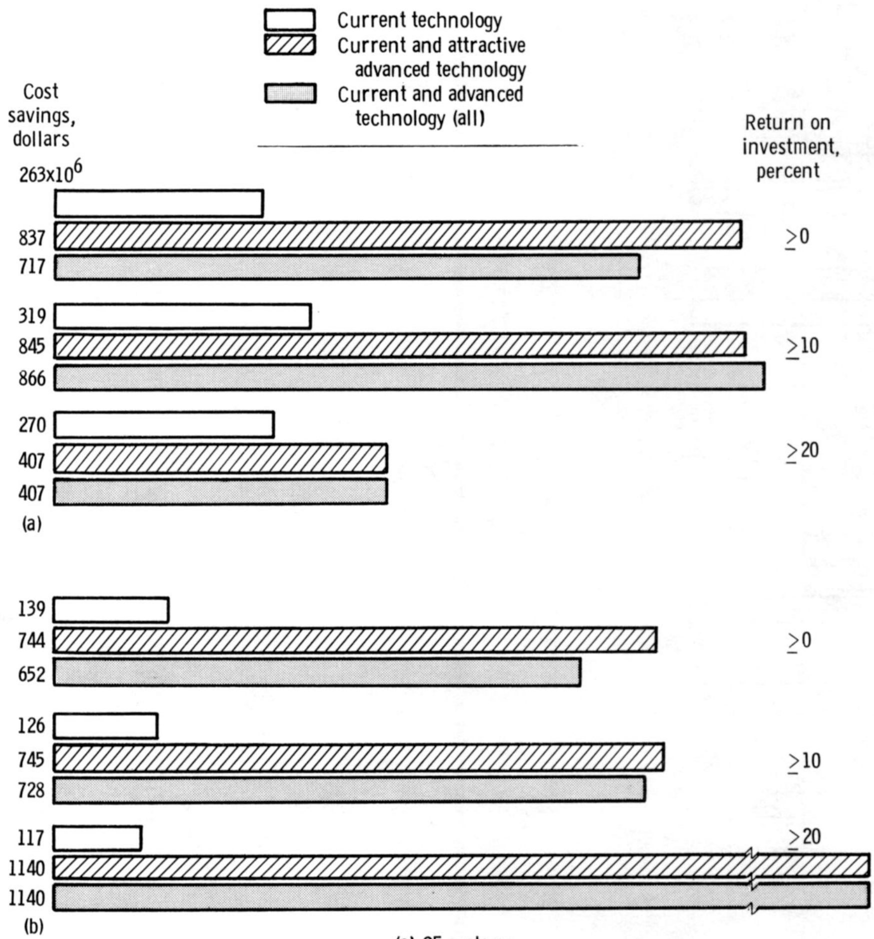
(a) GE systems.
(b) UTC systems.

Figure 6.4-1. - Potential national fuel energy savings relative to technology level and return on investment with no power export allowed.



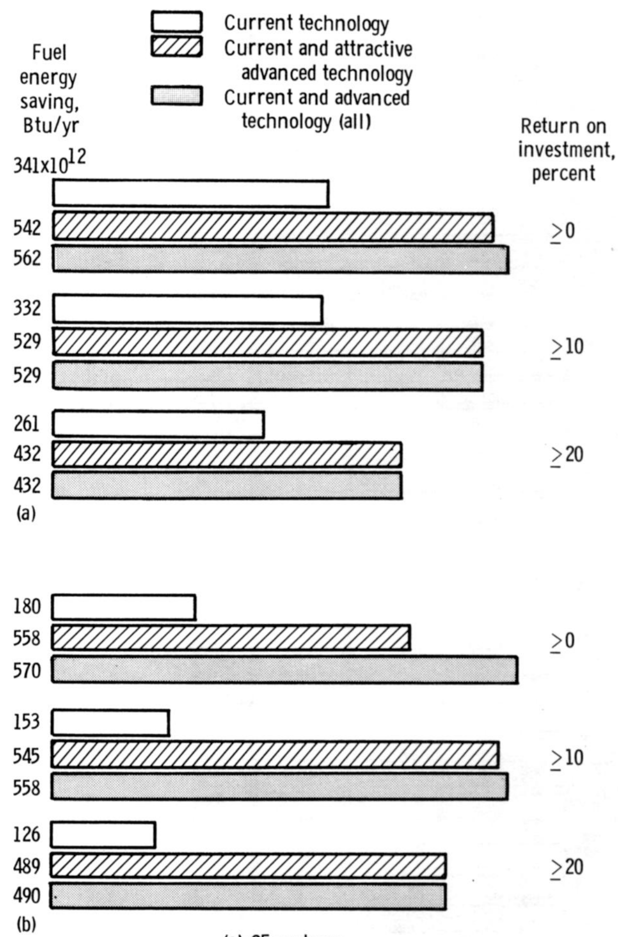
(a) GE systems.
(b) UYC systems.

Figure 6.4-2. - Potential national emissions savings relative to technology level and return on investment with no power export allowed.



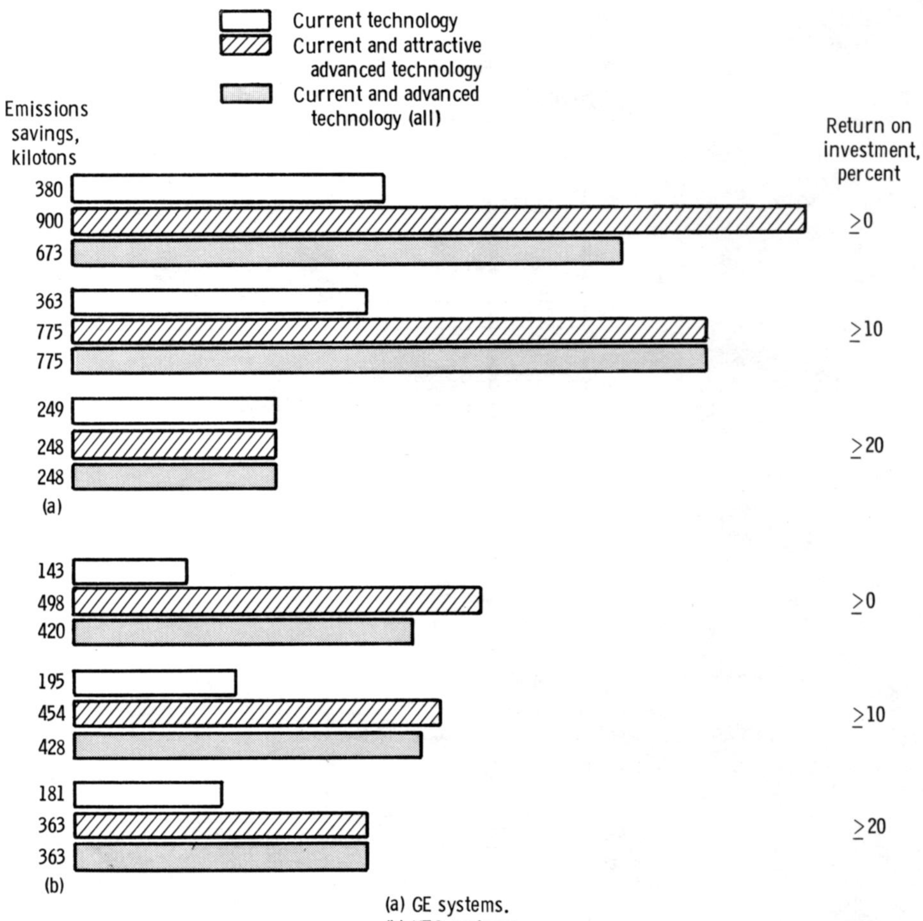
(a) GE systems.
(b) UTC systems.

Figure 6.4-3. - Potential national cost savings relative to technology level and return on investment with no power export allowed.



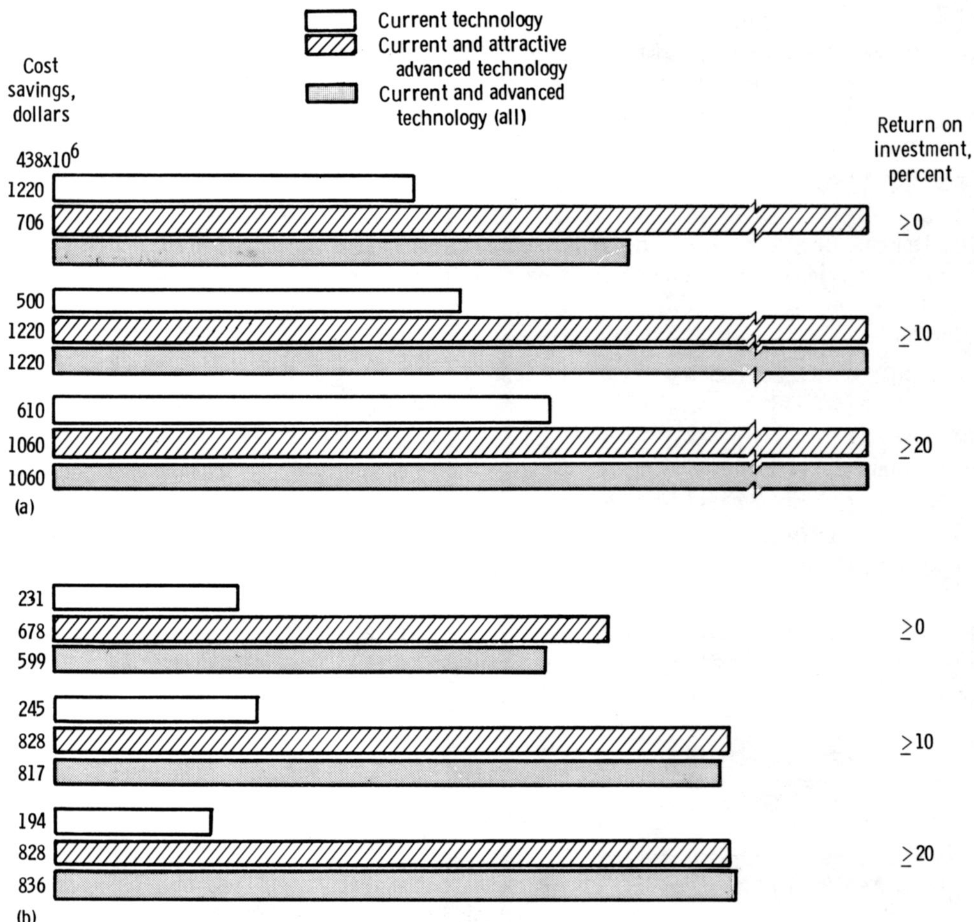
(a) GE systems.
(b) UTC systems.

Figure 6.4-4. - Potential national fuel energy savings relative to technology level and return on investment with power export allowed.



(a) GE systems.
(b) UTC systems.

Figure 6.4-5. - Potential national emissions savings relative to technology level and return on investment.



(a) GE systems.
(b) UTC systems.

Figure 6.4-6. - Potential national cost savings relative to technology level and return on investment with power export allowed.

7.0 CONCLUDING REMARKS AND PERSPECTIVES ON STUDY RESULTS

Gerald J. Barna

The Cogeneration Technology Alternatives Study (CTAS) was a broad study aimed at identifying the most attractive advanced energy conversion systems that could significantly advance the use of coal or coal-derived fuels for industrial cogeneration applications. As such, the study was concerned exclusively with the potential technical, economic, and environmental merits of advanced cogeneration systems. The study provided relative comparisons and evaluations of the advanced energy conversion systems studied. This was done through a government-industry team approach. Most of the basic data were provided through contracted studies with teams of industrial concerns knowledgeable in each of the various energy conversion systems studied, balance-of-plant equipment, industrial process requirements, and other elements necessary for establishing the technical, economic, and environmental characteristics of complete cogeneration systems. In addition to the contractor results the NASA Lewis Research Center provided further analyses of the data developed by the contractors and made an independent evaluation of the advanced systems, the results of which are presented as part of this report.

Although cases for systems using technology representative of current commercially available equipment were carried through the study to serve as a baseline for assessing the benefits of technological advancements, the study did not attempt to compare these current-technology systems or to assess the benefits of the cogeneration concept itself. Furthermore no attempt was made to propose solutions to institutional or regulatory barriers currently inhibiting more widespread use of industrial cogeneration.

On the basis of Lewis' evaluation of the overall study results, attractive advanced energy conversion systems were identified and placed into two groups as indicated in the following table:

Most attractive systems	
Steam turbines	Coal/atmospheric-fluidized-bed furnace (AFB) Coal/pressurized-fluidized-bed furnace (PFB)
Open-cycle gas turbine	Coal-derived liquid fuel, residual grade
Combined cycles	Coal-derived liquid fuel, residual grade
Additional attractive systems	
Open-cycle gas turbines	Coal/AFB Coal/PFB Integrated coal gasifier
Closed-cycle gas turbines	Coal/AFB
Molten carbonate fuel cells	Integrated coal gasifier Coal-derived liquid fuel, distillate grade

The other advanced systems studied did have attractive cogeneration results in one or more industrial process plant applications; however, in almost all cases, at least one of the systems in the preceding table had superior results in those applications. An important result of the study was that as a class the advanced energy conversion systems showed significant advantages over systems using current commercially available technology in terms of energy savings, emissions reductions, and economics.

Although the study did not provide estimates of research and development costs or assess development risks for the various systems, the identification of the research and development needed to bring the various technologies to commercial fruition was an important product of the CTAS effort. The technological advancements required to achieve the performance, economic, and environmental results calculated for those advanced systems identified as the most attractive are therefore discussed here to give perspective to the study results.

For the advanced steam systems the development and commercialization of the atmospheric- and pressurized-fluidized-bed (AFB and PFB) furnaces are the principal advancements assumed. For the PFB furnace subsystem this includes development of effective particulate removal systems with moderate costs or the development of approaches to turbine protection that would enable the gas turbine downstream of the PFB to operate reliably and with acceptable life in the erosive and corrosive effluent from the fluidized-bed furnace. The principal advancements for the open-cycle gas turbine and combined-cycle systems are in the gas turbine component. These are the development of gas turbines with the capability for long-lived and environmentally acceptable operation while using minimally processed coal-derived liquid fuels. Advancements in materials (particularly erosion- and corrosion-resistant coatings) and combustion concepts that limit oxides-of-nitrogen formation from the high-fuel-bound-nitrogen, coal-derived liquids are required. In addition, higher turbine inlet temperatures than those characteristic of current commercially available engines were found to be of benefit. Most of the benefits can be obtained through modest increases in turbine inlet temperature. Finally the option of steam injection was found to be beneficial in a number of industrial process applications.

For the open- and closed-cycle gas turbine systems using an AFB or PFB furnace the principal additional technological advancement over the steam systems using these advanced furnaces is that of a higher temperature heat exchanger with air or helium as the working fluid rather than steam. For the open-cycle gas turbine (or combined cycle) burning low- or intermediate-Btu gas produced in an integrated gasifier the major requirement is demonstration of the complete system including integration and control. In addition, higher gas turbine inlet temperatures were found to be beneficial. As for the coal-derived-liquid-fueled turbines modest increases in turbine inlet temperature can provide most of the benefits. For the molten carbonate fuel cell systems the development of long-lived fuel cells and related subsystems including reformers and the like was the principal technological advancement assumed. For the fuel cell system using low- or intermediate-Btu gas produced by an integrated gasifier, demonstration of the complete system including integration and control is also required.

Although a broad range of options was considered for each type of advanced system, all possible configurations of the various systems could not, of course, be covered in the study. The configurations studied were those felt by the various industrial team members to be most appropriate for industrial cogeneration applications between 1985 and 2000. Improvements in results, particularly for those advanced systems not previously studied in detail for industrial cogeneration applications, could be expected. On the other hand, the estimated capital cost often increases as more detailed studies are performed and the technology proceeds toward commercial fruition, particularly for the more advanced systems. For those systems identified as attractive more-detailed studies are required to more precisely evaluate their potential benefits. Finally it is important to keep in mind that the relative comparisons and evaluations of the systems made in CTAS apply only to industrial cogeneration applications. Different relative attractiveness could very well be found for other applications such as utility (power only) applications, commercial and residential total energy applications, or institutional and governmental installation applications, where the technical and economic requirements can be significantly different from those studied herein.

APPENDIX A

DESCRIPTION OF REPORTS ON THE COGENERATION TECHNOLOGY ALTERNATIVES STUDY (CTAS)

John W. Dunning

This NASA report presents a detailed comparison and evaluation of the CTAS results, concentrating primarily on the Lewis in-house analyses. In addition, NASA has prepared a summary report presenting the objectives, scope, approach, and major results from the entire CTAS effort. A complete listing of CTAS reports is as follows:

(1) Cogeneration Technology Alternatives Study (CTAS). NASA Final Report.

Volume I - Summary. NASA TM-81400, 1980.

Volume II - Comparison and Evaluation of Results. NASA TM-81401, 1984.

(2) Cogeneration Technology Alternatives Study (CTAS) - General Electric Company Final Report.

Volume I - Summary Report. DOE/NASA/0031-80/1, NASA CR-159765, 1980.

Volume II - Analytical Approach. DOE/NASA/031-80/2, NASA CR-159766, 1980.

Volume III - Industrial Process Characteristics. DOE/NASA/0031-80/3, NASA CR-159767, 1980.

Volume IV - Energy Conversion System Characteristics. DOE/NASA/0031-80/4, NASA CR-159768, 1980.

Volume V - Cogeneration System Results. DOE/NASA/0031-80/5, NASA CR-159769, 1980.

Volume VI - Computer Data. DOE/NASA/0031-80/6, NASA CR-159770, 1980.

(3) Cogeneration Technology Alternatives Study (CTAS) - United Technologies Corporation Final Report.

Volume I - Summary Report. DOE/NASA/0030-80/1, NASA CR-159759, 1980.

Volume II - Industrial Process Characteristics. DOE/NASA/0030-80/2, NASA CR-159760, 1980.

Volume III - Energy Conversion System Characteristics. DOE/NASA/0030-80/3, NASA CR-159761, 1980.

Volume IV - Heat Sources, Balance of Plant, and Auxiliary Systems. DOE/NASA/0030-80/4, NASA CR-159762, 1980.

Volume V - Analytical Approach and Results. DOE/NASA/0030-80/5, NASA CR-159763, 1980.

Volume VI - Computer Data. DOE/NASA/0030-80/6, NASA CR-159764, 1980.

The first volume of each set of contractor reports is a summary report addressing their contracted study. The NASA and contractor summary reports provide a sufficient level of detail for many readers. However, for other readers more detail in one or more aspects of the study may be of interest. The more-detailed NASA and contractor reports address the needs of those readers.

Reports from other studies closely related to CTAS:

(1) Manvi, R.: Regional Characteristics Relevant to Advanced Technology Cogeneration Development. (Jet Propulsion Lab., JPL-PUB-81-61; NASA Contract NAS7-100.) NASA CR-164697, July 1981.

(2) Nanda P.; et al.: Advanced Cogeneration Technology Economic Optimization Study. (Mathtech, Inc., REPT-2150; NASA Contract JPL-955559.) NASA CR-163887, Dec. 1980.

(3) Cogeneration Technology Alternatives Study (CTAS) Topical Report - Time-Varying Results for Selected Industrial Applications. (United Technologies Corp., FCR-2806; NASA Contract DEN3-30.) DOE/NASA/0030-7, NASA CR-165247, Oct. 1980.

APPENDIX B

METHODOLOGY USED FOR ECONOMIC ANALYSIS

Gary Bollenbacher

In the field of capital investment analysis, or engineering economics, numerous methods are used to compare investment alternatives. The most commonly calculated indicators of economic worth are the net present value, the internal rate of return, the minimum annual revenue requirements, and the payback period. Each of these indicators has some advantages, disadvantages, and limitations. Furthermore each method of economic analysis comes in a variety of versions that differ from one another by the assumptions or simplifications that are made or by the degree of sophistication employed. These variations will often yield widely differing numerical results but, if used to compare two alternatives, will generally lead to similar conclusions.

In light of the many methods available for the analysis of capital investments and given the variety of specific approaches to each method, it was recognized early in the CTAS study that a degree of standardization needed to be introduced into the economic analysis to be adhered to by both contractors and by the Lewis Research Center. Such standardization facilitates comparison of results from the two contractors, ensures that real differences in the results will not be obscured by arbitrary differences introduced by the economic analysis, and prevents the economic analysis from introducing apparent differences into the results that in fact do not exist.

This appendix describes and compares the primary economic indicators used in the CTAS study. The detailed economic ground rules that were specified to insure comparability of the results are given in appendix C.

B.1 INDICATORS OF ECONOMIC WORTH USED IN THE CTAS STUDY

Two economic analysis methods were specified in the CTAS contract:

(1) Internal rate of return on incremental investment
(2) Levelized annual energy cost (LAEC)

Detailed ground rules for the calculation of these two parameters were specified by Lewis to both contractors in order to insure comparability of the results from the two contracts. The ground rules were established after discussions with both contractors, the Jet Propulsion Laboratory, and the Department of Energy. A complete list of the ground rules is given in appendix C of this report. With one minor exception both contractors adhered to the ground rules as required.

The levelized annual energy cost formed the basis for an additional parameter that was used extensively throughout the CTAS study. This additional parameter is the cost saving ratio and is defined in section 2.5.

Another parameter that was used in the study is the investment ratio. This is the ratio of the capital investment required for a cogeneration system to the capital investment for a conventional energy system.

In addition to the required economic analysis each contractor could, at his option, perform such additional economic analyses as desired. Both contractors elected to do so. The optional economic analysis was not subject to any Lewis-specified ground rules. One parameter that was calculated by both contractors was the payback period.

The return on investment, levelized annual energy cost, and investment ratio are discussed in greater detail in subsequent sections of this appendix.

B.2 INTERNAL RATE OF RETURN ON INCREMENTAL INVESTMENT

For brevity the internal rate of return on incremental investment is called return on investment (ROI). ROI is defined as that rate r that causes the following equation to be true:

$$C = \sum_{j=1}^{n} S_j/(1 + r)^j$$

In this equation, C represents the incremental investment, S_j represents the annual incremental cash flow related to the energy system, and n is the useful life of the investment.

The ROI was chosen as one of the primary economic indicators to be used in this study of industrial cogeneration because it is a parameter commonly employed by the industrial community. Using ROI to evaluate investment alternatives is generally appropriate if the alternatives being compared have equal lives, if the annual cash flows can be predicted with reasonable certainty, and if the incremental cash flow stream has exactly one sign reversal, that is, a period of cash outflow (the initial investment) followed by a period of cash inflow (the return).

The ROI, as defined in the economic ground rules, is the ROI on total incremental investment rather than the ROI on the equity fraction. This ROI was chosen because the focus of the study was on comparing and evaluating advanced cogeneration technologies. Using the return on equity fraction would have obscured the comparison of advanced technologies by introducing into the results variations that are caused by differences in investment financing.

There are some computational problems associated with ROI when there are no cash flow reversals. This situation occurs when the investment under evaluation requires a higher capital expenditure and higher annual outlay than the reference system or when both the capital investment and the annual outlays are lower than those for the reference system. The first situation clearly describes an investment that is economically unattractive; the second situation is just as clearly economically desirable. In both cases, however, the ROI cannot be calculated. Another difficulty that can arise is the situation where the capital cost of the system under evaluation is less than the capital cost of the reference system. In such cases the calculated ROI is the return realized by investing in the reference system. Each of these situations arose during the course of the CTAS study. Other computational problems can arise when calculating ROI's but did not occur for investments analyzed during the CTAS study.

The ROI calculated for the CTAS study is an inflation-free, after-tax value. It includes the affect of Federal and state income taxes, which were combined into a composite tax rate. The ROI calculations also take into account the effects of an investment tax credit, state and local ad valorum taxes, and insurance. Fuel costs and electricity costs were assumed to escalate at a constant annual rate. The ground rules for the ROI calculations were chosen such that for an investment that breaks even the calculated ROI will be the after-tax cost of capital. The after-tax cost of capital assumed for this study was 5.35 percent. Thus for a calculated ROI of 5.35 percent, the return after paying all expenses will just be sufficient to recover the incremental investment and to pay for the cost of capital. An ROI of zero would indicate that the return on the investment is just sufficient to recover the incremental capital investment and no more. As a minimum then the ROI of a cogeneration system should be 5.35 percent.

In most cases industry requires a higher ROI before considering a capital investment. The minimum required ROI is commonly called the hurdle rate. When comparing an industry's hurdle rate to a calculated ROI, it is important that both values are on a consistent basis. For example, if the calculated ROI is an inflation-free value, the hurdle rate must likewise be inflation free. Similarly, both the ROI and the hurdle rate should be either before or after taxes.

If the annual savings resulting from an investment are constant over the life of that investment, the ROI can be plotted as shown in figure B-1. Note that the figure is valid for a 30-year investment only. If the annual savings are not constant, figure B-1 is still valid provided that the annual savings are appropriately converted to an equivalent constant annual savings.

As can be seen from the figure for ROI's greater than 10 percent the following expression will hold:

$$\mathrm{ROI} = \frac{\text{Annual return}}{\text{Capital investment}} \times 100$$

or

$$\frac{100}{\mathrm{ROI}} = \frac{\text{Capital investment}}{\text{Annual return}}$$

The right side of this equation will be recognized to be one definition of payback. Therefore

$$\text{Payback} = \frac{100}{\mathrm{ROI}}$$

for values of ROI greater than 10 percent. In other words the inverse of the ROI can be interpreted as an approximation of the payback period (i.e., the number of years it will take before the investment is recovered). For ROI's less than 10 percent this inverse relationship will overestimate the payback period.

B.3 LEVELIZED ANNUAL ENERGY COST

The levelized annual energy cost is defined as the minimum constant annual revenue that, over the projected life of the investment, will repay all of the expenses associated with owning and operating the energy system. The expenses of owning and operating an energy system consist of depreciation, cost of capital, Federal and state income taxes, local taxes and insurance, fuel costs, and operation and maintenance costs. Although many of these costs will vary from year to year, the levelized annual energy cost will be a constant but equivalent value. The conversion of a sequence of annual costs into an equivalent constant cost greatly facilitates the comparison of two or more energy systems.

The levelized annual energy approach is a method of economic analysis commonly employed in the electric utility industry, where it is more generally referred to as the minimum revenue requirements analysis. The approach, however, is equally applicable to an industrial environment, provided that revenues are unaffected by the investment. In that case the minimum-cost system will maximize profits over the life of the investment. The assumption that revenues are unaffected is valid for many capital investments; in particular it is a fair assumption for energy systems. Even where revenues do change as a result of the investment, as is the case when excess electricity from a cogeneration system is sold to a utility, the method can be employed, provided the change in revenues is small and can be predicted with reasonable certainty. In this case revenues can be credited against costs to arrive at a net cost.

Inherent in the method are several other assumptions, all of which must be satisfied if the method is to be employed:

(1) The investment is made at the start of the service life.
(2) The investing organization can be treated as a pool of money with unchanging ratio of debt to equity.
(3) Tax rates are constant throughout the service life.
(4) If an investment tax credit is assumed to apply to the investment, the investing organization must pay sufficient income tax each year to take full advantage of the investment tax credit.

The levelized annual energy cost (LAEC) is computed as follows:

LAEC = Levelized fixed charges + Levelized operating costs

The levelized fixed charges are those costs that must be borne by the investing organization regardless of whether the system is operating. The levelized fixed charges include the recovery of the invested capital, the cost of the invested capital (i.e., interest costs and dividend on preferred and common equity capital), and income taxes that must be paid out of earnings before dividends can be distributed.

The levelized fixed charges are given by

Levelized fixed charges = (Capital investment) x (Fixed charge rate)

The fixed charge rate is a function of investment life, cost of capital, investment tax credit, income tax rate, and tax depreciation method and life. The fixed charge rate is also a function of the accounting treatment assumed for the investment tax credit and for accelerated tax depreciation. The specific algebraic expressions used for calculating the fixed charge rate in this study are given in appendix C.

The levelized operating cost is computed as follows:

$$\text{Levelized operating cost} = (\text{Annual operating cost in year zero}) \times (\text{Levelizing factor})$$

This equation is applied to each cost individually, and the individual levelized operating costs are summed to obtain the total levelized operating cost. Year zero, as used above, is the year in which the investment is assumed to have been made; it is the year preceding the first year of energy system operation. The details of calculating the levelizing factor are given in appendix C. In general, the levelizing factor will depend on how rapidly any specific operating cost escalates relative to the general inflation rate. If costs remain constant over the life of the investment, the levelizing factor equals 1.0. For costs that increase at a constant annual rate the levelizing factor is easy to compute. The computations get more complex if costs vary randomly or if the rate of increase from year to year is not constant. In this study all relevant costs were assumed either to remain constant over the life of the investment or to rise at the rate of 1 percent per year.

The levelized annual energy cost suffers from none of the computational problems associated with the ROI. The LAEC can always be computed and the result will be unique. However, the LAEC does have the drawback that it is not a dimensionless number. It is expressed in dollars per year, which makes a comparison of energy conversion systems between industries of different sizes difficult. To overcome this difficulty, a dimensionless levelized annual energy cost saving ratio (LAECSR) was defined as shown in section 2.5. This cost saving ratio is positive for any cogeneration system having a lower LAEC than the corresponding noncogeneration system in the same industry.

If the LAECSR = 0, the cogeneration system and the reference noncogeneration system have the same levelized annual energy cost. From an economic viewpoint, two systems with the same annual energy cost are equivalent.

B.4 INVESTMENT RATIO

The investment ratio is defined in section 2.5. The capital investment is the investment after making an allowance for construction adders. This parameter essentially creates a nondimensional capital investment to facilitate comparison between industries of different sizes.

In this study the investment ratio varied over a wide range, depending on fuel type.

B.5 COMPARISON OF RETURN ON INVESTMENT, LEVELIZED ANNUAL ENERGY COST, AND COST SAVING RATIO

If the various energy conversion systems that were studied were arranged in order of increasing ROI and again in the order of increasing LAECSR, the two resulting sequences would not be the same. In other words the economic ranking of systems will depend very much on which economic parameter is used as the measure of economic goodness. This problem is further illustrated in figure B-2, in which LAECSR is plotted against ROI for several energy conversion systems selected from four industries. On the basis of ROI alone the systems toward the right of the plot would appear to be the preferred choices while the systems at the top of the plot would be chosen on the basis of LAECSR only. This section of appendix B explores this seeming contradiction and seeks to clarify the interpretation of ROI versus LAECSR.

To help clarify the relationship among ROI, levelized annual energy cost, LAECSR, and investment ratio, four representative cogeneration systems and two noncogeneration systems were selected from the chlorine industry. The capital costs and operating costs of the systems were then modified to more clearly illustrate the comparison of the various economic parameters. The systems, their origins, and the capital and operating costs, as modified, are shown in table B-1. The results of the economic analyses of these systems are given in table B-2 and are presented graphically in figures B-3 and B-4. Note that the systems were modified such that systems B and C have the same capital cost as do systems D, E, and F. Similarly, systems A, B, D, and F have equal levelized annual costs and the same is true for systems C and E.

A review of the results of the economic analysis shown in table B-2 illustrates the following conclusions:

(1) All of the systems with the same levelized cost as the reference system have the same ROI. That ROI is equal to the after-tax cost of capital. The ROI is independent of the capital investment.

(2) Systems with levelized costs less than those of the reference system (i.e., systems with LAECSR greater than zero) have ROI's greater than the after-tax cost of capital. The higher the capital cost, the lower will be the ROI.

It should also be observed that neither ROI nor LAECSR can discriminate between systems B, D, and F. System B, however, has a lower investment ratio than either D or F. Systems D and F cannot be distinguished on the basis of any of the numeric economic parameters discussed.

The levelized annual energy cost does not differentiate between capital investment expenditures and operating costs. All costs are transformed into equivalent annual operating costs and summed. ROI on the other hand is a rough measure of the annual savings per dollar invested. One would expect therefore that the two parameters would react quite differently to changes in capital cost. This is illustrated in figure B-5. The solid curve in the figure was obtained by increasing capital cost and decreasing operating costs of systems B to F in such a way as to keep levelized annual energy cost constant. As expected, the change in ROI is very significant, depending very strongly on the cost of each system relative to the reference system. The dashed curve was obtained by first changing the capital cost of reference system A while holding

the total levelized cost fixed. The capital and operating costs of systems B to F were then changed as before. Thus for any given value of investment ratio, capital costs on the dashed curve are double what they are on the solid curve. The results show that for a given CSR and investment ratio, the ROI depends not only on relative capital costs (i.e., the investment ratio), but also on the absolute level of capital costs.

TABLE B-1. - REPRESENTATIVE SYSTEMS TO ILLUSTRATE COMPARISON OF ROI, LAEC, CSR, AND INVESTMENT RATIO

System	System before modification	Contractor	Capital cost (after construction adders), 1978 dollars	Annual operating costs in 1990, 1978 dollars		
				Fuel cost	Electricity cost	O&M cost
A	Residual-burning noncogeneration system	UTC	3.004×10^6	8.571×10^6	25.933×10^6	0.087×10^6
B	Coal-burning noncogeneration system		16.690	5.314	27.840	.216
C	Steam-injected gas turbine		16.690	21.387	----------	1.932
D	Compound thermionics		83.744	26.140	----------	1.306
E	Low-speed diesel with pulverized coal		83.744	16.031	----------	1.170
F	Medium-speed diesel	GE	83.744	33.785	-8.982	2.800

TABLE B-2. - RESULTS OF ECONOMIC ANALYSIS OF REPRESENTATIVE SYSTEMS

System	Capital cost (after construction adders), 1978 dollars	Levelized annual energy cost, LAEC, dollars	Comparison with system A		
			Investment ratio	LAECSR, percent	Return on investment percent
A	3.004×10^6	38.915×10^6	-----	----	----
B	16.690	38.915	5.55	0	5.3
C	16.690	27.491	5.55	29.5	49.4
D	83.744	38.915	27.9	0	5.3
E	83.744	27.491	27.9	29.4	15.0
F	83.744	38.915	27.9	0	5.3

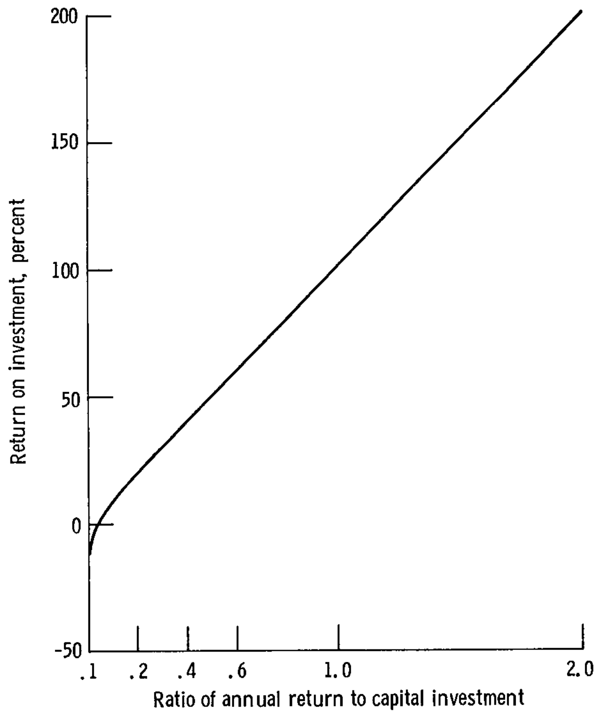


Figure B-1. - Relationship of return on investment to annual return for 30-year investment. (Annual savings are assumed to be constant over life of investment.)

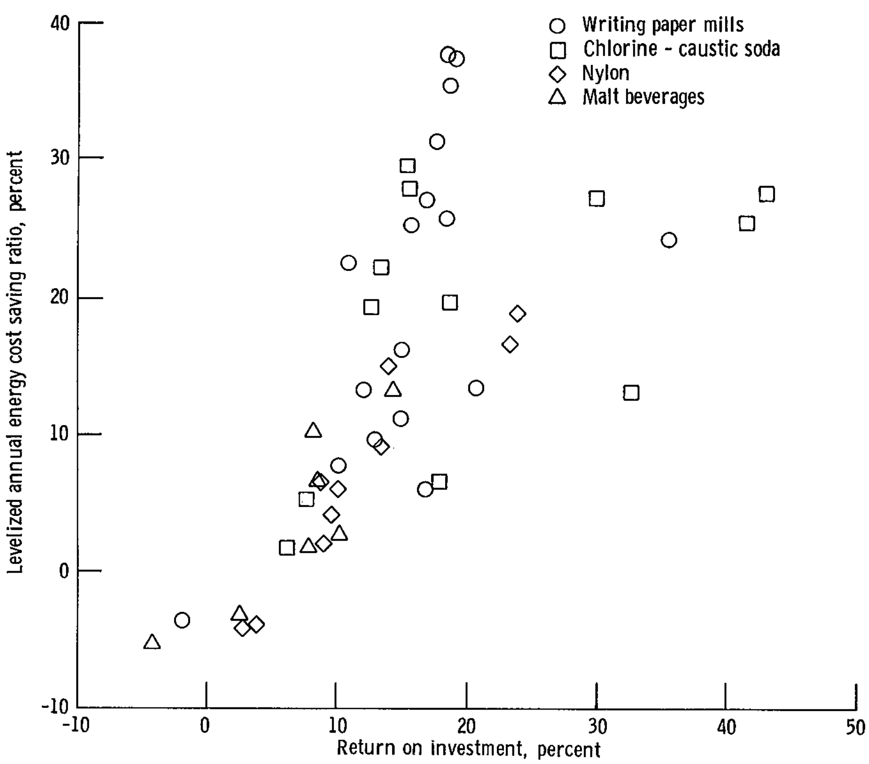


Figure B-2. - Levelized annual energy cost saving as a function of return on investment for writing paper mills, chlorine-caustic soda plants, nylon plants, and malt beverage plants.

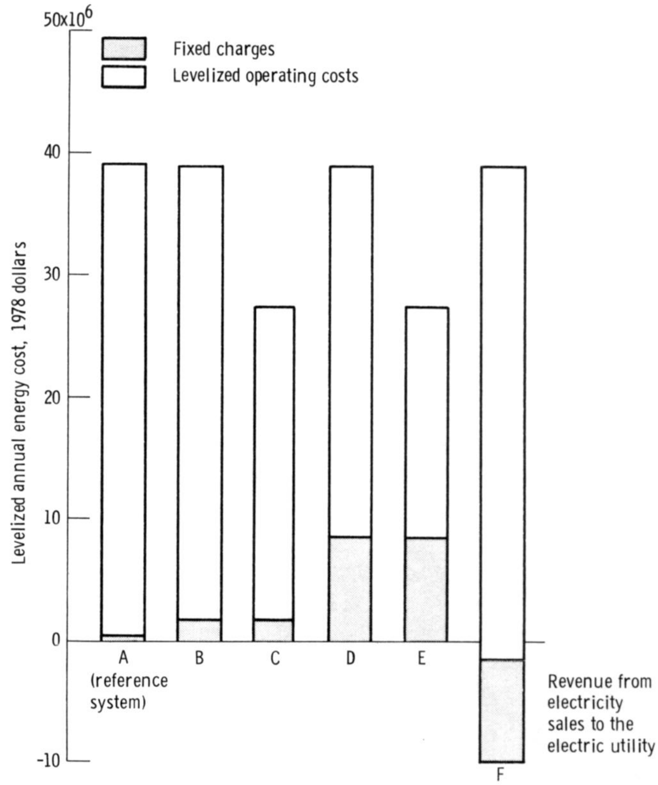


Figure B-3. - Levelized annual energy costs for illustrative systems from table B-1 used with chlorine - caustic soda plants.

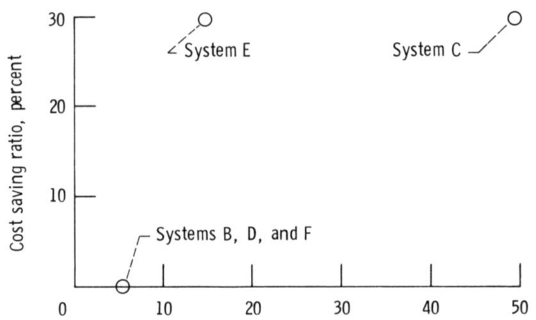


Figure B-4. - Cost saving ratio as function of return on investment for illustrative systems from table B-1.

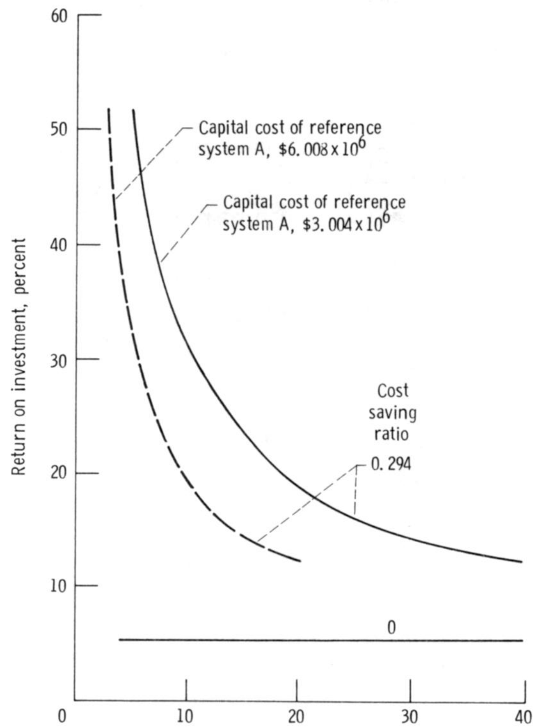


Figure B-5. - Return on investment as a function of investment ratio for illustrative systems from table B-1.

APPENDIX C

GROUND RULES FOR ECONOMIC ANALYSIS

Gary Bollenbacher

This appendix lists the ground rules and assumptions specified by Lewis for the CTAS economic analysis. It consists of four parts:

C.1 General Ground Rules
C.2 Ground Rules Applicable to a Rate-of-Return Analysis
C.3 Ground Rules Applicable to a Levelized-Annual-Cost Analysis
C.4 Illustrative Economic Analysis with Detailed Solution

This appendix is primarily concerned with methodology and not with specific numeric values. The variables for which numeric values must be specified in order for the basic methodology described herein to be used are as follows:

(1) Cost of debt at zero inflation
(2) Cost of preferred equity at zero inflation
(3) Cost of common equity at zero inflation
(4) Debt fraction
(5) Preferred equity fraction
(6) Common equity fraction
(7) Composite (Federal, state and local) income tax rate
(8) Investment tax credit rate
(9) Economic (useful) life of investment
(10) Depreciation method for income tax (straight line or sum-of-the-year digits)
(11) Depreciation life for income tax
(12) Capital cost estimate
(13) Reference year for capital cost estimate
(14) Construction time
(15) Capital cost escalation rate
(16) First year of operation
(17) Other taxes (percent of investment)
(18) Insurance cost (precent of investment)

The following are required for each item of expense or revenue associated with the investment:

(19) Cost in year zero
(20) Escalation rate

Both contractors adhered to these ground rules with one exception. One of the contractors deviated slightly from equation (17) given later in this appendix. The deviation had only a minor effect on numerical results. The substance of the ground rules given here is the same as those given to the contractors. Changes have been made to improve the presentation and clarity.

C.1 GENERAL GROUND RULES

The following general ground rules or assumptions shall apply to all economic analyses:

(1) General inflation, that is, the change in the value of the dollar, shall be assumed to be zero.

(2) Real escalation rates (i.e., changes in costs of specific items higher or lower than the change in the value of the dollar) shall be explicitly accounted for. (Note that escalation rates can be positive or negative.)

(3) Income taxes shall be included in the analysis.

(4) Investment tax credit shall be included in the analysis and shall be treated as a reduction in the first year's taxes.

(5) The economic analysis method employed shall be capable of treating accelerated tax depreciation (accelerated depreciation methods and depreciation lives less than economic lives).

(6) Other taxes shall be assumed to be a percentage of the capital investment.

(7) Insurance costs shall be assumed to be a percentage of the capital investment.

(8) Insurance costs and other taxes shall be assumed to be constant for the life of the investment.

(9) Salvage or residual values shall be assumed to be zero.

(10) Cost increases during construction (due to capital cost escalation and cost of capital) shall be included in the analysis.

(11) Load factors and capacity factors shall be assumed to be constant throughout the economic life of the investment and to be an average annual value.

(12) The cost of capital used in the analysis shall be consistent with the assumption of zero inflation.

(13) The cost of capital shall be defined as

$$m = (1 - t)\, f_d i_d + f_p i_p + f_c i_c$$

or

$$m' = f_d i_d + f_p i_p + f_c i_c$$

where

m after-tax cost of capital

m' before-tax cost of capital

f_d ratio of debt capital to total capital

f_p ratio of preferred equity capital to total capital

f_c ratio of common equity capital to total capital

i_d, i_p, i_c costs of debt, preferred equity, and common equity, respectively, assuming zero inflation

t composite Federal, state, and local income tax rate

(14) The analysis shall be deterministic and not probabilistic.

(15) Assumptions used in the levelized cost analysis and in the rate-of-return analysis shall be consistent.

C.2 GROUND RULES APPLICABLE TO THE RATE-OF-RETURN ANALYSIS

Definition of Rate of Return

Fundamentally, the rate of return (ROR) is defined implicitly as the rate r that equates the present value of all future cash flows with the initial capital investment. In equation form ROR is defined as

$$C = \sum_{j=1}^{n} \frac{S_j}{(1 + r)^j} \qquad (1)$$

where

r annual rate of return

C initial capital investment at time $j = 0$

S_j annual net cash flow in year j

n life of investment

j index that counts number of years from time of initial investment

The net cash flow S_j, although it is composed of cash flows distributed throughout the year, shall be assumed to occur at the end of year j.

Definition of Incremental Rate of Return

The incremental rate of return is defined as the ROR on the incremental investment between two alternatives. Thus the incremental rate of return between investment alternatives A and B is the rate r implicitly defined by the following equations:

$$C_A - C_B = \sum_{j=1}^{n} \frac{(S_j)_A - (S_j)_B}{(1 + r)^j} \qquad (2)$$

$$C_A - \sum_{j=1}^{n} \frac{(S_j)_A}{(1 + r)^j} = C_B - \sum_{j=1}^{n} \frac{(S_j)_B}{(1 + r)^j} \tag{3}$$

$$\left[C - \sum_{j=1}^{n} \frac{S_j}{(1 + r)^j}\right]_A = \left[C - \sum_{j=1}^{n} \frac{S_j}{(1 + r)^j}\right]_B \tag{4}$$

In other words the incremental rate of return between two investment alternatives is the rate that equates the present value of the two investments. If one alternative is to do nothing, equation (4) reduces to equation (1).

Ground Rules

The following ground rules specifically applicable to the rate of return analysis shall be adhered to:

(1) The rate of return to be calculated is the rate of return on total investment C or on total incremental investment, $C_A - C_B$, rather than the equity fraction of the total or incremental investment.

(2) Discrete cash flows shall be assumed throughout, rather than continuous or distributed cash flows.

(3) All cash flows shall be assumed to occur at the end of the year.

(4) The capital investment shall be assumed to occur in a single cash outflow at time zero. (Time zero is defined as the end of construction and the start of the useful life of the investment.)

(5) The magnitude of the capital investment at time zero shall be equal to the capital cost estimate in constant-year dollars adjusted for real escalation to the start of construction and cost increases during construction as described here. Let K be the capital cost estimate (as distinct from expenditure or investment) of the energy system to be expressed in constant-year dollars. The term K does not include interest or escalation during construction or working capital. Then C, the capital cost expenditure used in the rate-of-return analysis, shall be defined as follows:

$$C = k_{m'} k_e K\ (1 + e_k)\ N^* - N_0 - L \tag{5}$$

where

$$k_{m'} = \text{Cost-of-capital factor} = e^{0.418m'L} \tag{6}$$

$$k_e = \text{Escalation factor} = e^{0.562\ (e_K)L} \tag{7}$$

K capital cost without cost of capital or escalation during construction

e_k real capital cost escalation per year (i.e., rate of capital cost change above or below rate of inflation)

L design and construction time, yr

N^* first full year of commercial operation of investment

N_0 year used as basis for cost estimate K

m' before-tax cost of capital

This formulation assumes that system operation starts at the beginning of year N^*. The factors k_m and k_e account for the cost of capital and the escalation during construction, respectively.

(6) All maintenance costs shall be treated as expenses rather than being capitalized.

(7) Cash flow in each year following the capital investment shall be defined as profit <u>before interest expense</u> plus book depreciation as illustrated in the income statement shown in table C-1. Note that all incomes (gross income, net income, and taxable income) are defined before interest expense.

An alternative, but equivalent, expression for cash flow is

$$\text{Cash flow} = \text{Revenues} - \text{Cash operating expenses} - \text{Income tax} \tag{8}$$

Since in most cases revenues and expenses must be estimated anyway, this formulation (eq. (8)) appears to be more natural to use and has the additional advantage that no assumptions regarding book depreciation need to be made.

The income tax as used in equation (8) can likewise be expressed in equation form.

$$\text{Income tax} = t\,(\text{Revenues} - \text{Cash operating expenses} - \text{Tax depreciation}) - \text{Tax credit} \tag{9}$$

where t is the tax rate.

The investment tax credit shall be computed as

$$\text{Investment tax credit} - cC \tag{10}$$

where

c investment tax credit rate (different tax credit rates may apply to each investment alternative)

C capital investment as defined in eq. (5)

C.3 GROUND RULES APPLICABLE TO LEVELIZED-ANNUAL-COST ANALYSIS

<u>Definition of Levelized Annual Cost</u>

The levelized annual cost of an investment is defined as the minimum constant net revenue required each year of the life of the project to cover all expenses, the cost of money, and the recovery of the initial investment. This

is the capital investment analysis approach commonly used by electric utilities; however, the methodology is equally applicable to other corporate investments.

The levelized annual energy cost shall be computed as follows:

Levelized annual cost = Levelized fixed charges + Levelized operating costs - Levelized revenues

(The only revenues to be considered here are those directly related to the investment.)

Ground Rules

(1) Retirement dispersion shall be neglected.
(2) Flow-through accounting shall be assumed throughout.
(3) The levelized cost to be computed is the net cost (i.e., the gross levelized cost less credit for revenues directly related to the investment, such as sales of byproducts).
(4) Since the purpose of this analysis is to determine the net energy cost, the cost of capital and not the desired rate of return, must be used in the analysis.
(5) The levelized fixed charges (LFC) shall be computed as follows:

$$LFC = C \times FCR \tag{11}$$

where

FCR fixed charge rate

C capital investment as defined in eq. (5)

(6) The fixed charge rate FCR shall be computed by using the following equations (ref. 2):

$$FCR = \left(\frac{CRF_{m,n_B}}{1 - t}\right)\left[1 - t(DEP) - c\right] \tag{12}$$

CRF_{m,n_B} capital recovery factor for after-tax cost of capital m and economic life n_B

t tax rate

c investment tax credit rate

DEP levelized depreciation factor as defined below

m after-tax cost of capital at assumed inflation rate

The term DEP is given for straight-line tax depreciation by

$$DEP = \frac{1}{n_T CRF_{m,n_T}} \tag{13}$$

and for sum-of-the-year-digits (SYD) tax depreciation by

$$DEP = \frac{2n_T \quad - \quad 1/CRF_{m,n_T}}{n_T(n_T + 1)m} \tag{14}$$

where

n_T tax depreciation life

m after-tax cost of capital at assumed inflation rate

CRF_{m,n_T} capital recovery factor for after-tax cost of capital m and tax lift n_T

(7) Expenditures and revenues occurring over the economic life of the investment shall be levelized as follows: For the general case, where costs (or revenues) vary arbitrarily from year to year the levelized annual cost (or revenue) is

$$LC = (CRF_{m,n})\ (PV) \tag{15}$$

where

$$PV = \sum_{j=1}^{n} \frac{P}{(1 + m)^j} \tag{16}$$

P_j expenditure (or revenue) in year j

CRF capital recovery factor

m after-tax cost of capital

n economic life of investment

For costs (or revenues) that vary at a constant annual rate,

$$LC = P_0\ (CRF_{m,n}/CRF_{k,n}) \tag{17}$$

One contractor deviated from this equation and computed the levelized cost by using the following equation:

$$LC = P_1 \, (CRF_{m,n}/CRF_{k,n})$$

where

P_0 cost (or revenue) in year $j = 0$

e_p constant annual escalation rate

and

$$k = \frac{1 + m}{1 + e_p} - 1 \qquad (18)$$

For costs that are constant

$$LC = P_0 \qquad (19)$$

where P_0 is the cost in year $j = 0$ and $P_0 = P_j$ for all j.

C.4 ILLUSTRATIVE ECONOMIC ANALYSIS

This hypothetical example compares a cogeneration energy conversion system with a noncogeneration system. The example is presented in four parts:

(1) Input Data and Assumptions (table C-2)
(2) Rate-of-Return Analysis (tables C-3 to -6)
(3) Levelized Annual Energy Cost (tables C-7 to -9)
(4) Levelized O&M, taxes, and insurance (table 10)
(5) Summary of Results (table C-11 and fig. C-1)

TABLE C-1. - INCOME STATEMENT FOR COMPUTATION OF CASH FLOW

Revenues

\- Cash operating expenses

Fuel costs

Purchased electricity costs

Operating costs

Maintenance costs

Property tax

Insurance

Supplies

etc.

\- Book depreciation

= Gross income before interest and tax

\- Income tax

= Net income before interest expense

\+ Book depreciation

= Cash flow

Gross income before interest and tax

\+ Book depreciation

\- Tax depreciation

= Taxable income

x Tax rate

= Income tax before investment tax credit

\- Investment tax credit

= Income tax

TABLE C-2. - INPUT DATA AND ASSUMPTIONS

	Noncogeneration system	Cogeneration system
Capital cost estimate, 1978 dollars	$13x10^6$	$16x10^6$
Construction time, yr	1	3
First year of operation	1985	1985
Annual O&M cost, 1978 dollars	$800x10^3$	$950x10^3$
Real O&M escalation rate	0	0
Economic life, yr	25	25
Real capital cost escalation rate	0	0
Tax depreciation life, yr	25	25
Method of tax depreciation	Sum-of-the-year digits	Sum-of-the-year digits
Annual energy consumption, Btu:		
Purchased electricity	$200x10^9$	0
Coal	$950x10^9$	0
Distillate	0	$750x10^9$
Sales of excess electricity	0	0
Cost of debt at zero inflation	0.03	
Cost of common equity at zero inflation	0.09	
Debt ratio	0.40	
Common equity ratio	0.60	
Income tax rate	0.50	
Investment tax credit:		
For conventional energy systems	0.10	
For cogeneration systems	0.20	
Insurance and local taxes, percent of investment cost	0.03	
Real energy escalation rates, percent:		
Distillate	2	
Purchased electricity	1	
Coal	3	
Through 1995	0	
After 1995		
Energy costs, 1978 dollars/106 Btu (in 1985):		
Purchased electricity	10.00	
Coal	2.00	
Distillate	4.00	

TABLE C-3. - RATE-OF-RETURN ANALYSIS

[See equation (5) of appendix C.]

	Noncogeneration system	Cogeneration system
Capital cost without cost of capital or escalation during construction, K, dollars	13×10^6	16×10^6
Real capital cost escalation per year (i.e., rate of capital cost change above or below rate of inflation), e_k	0	0
Design and construction time, L, yr	1	3
Before-tax cost of capital at zero inflation	0.066	0.066
First full year of commerical operation, N*	1985	1985
Cost-of-capital factor, k_m,	1.028	1.086
Escalation factor, k_e	1	1
Capital cost expenditure, C, dollars	13.364×10^6	17.380×10^6

TABLE C-4. - ANNUAL ENERGY COSTS

Year	Noncogeneration system		Cogeneration system (distillate)
	Coal	Purchased electricity	
	Annual energy cost, 1978 dollars		
1984	1.845×10^6	1.980×10^6	2.941×10^6
1985	1.900	2.000	3.000
1986	1.957	2.020	3.060
1987	2.016	2.040	3.121
1988	2.076	2.061	3.184
1989	2.138	2.081	3.247
1990	2.203	2.102	3.312
1991	2.269	2.123	3.378
1992	2.337	2.144	3.446
1993	2.407	2.166	3.515
1994	2.479	2.187	3.585
1995	2.553	2.209	3.657
1996		2.231	3.730
1997		2.254	3.805
1998		2.276	3.881
1999		2.299	3.958
2000		2.322	4.038
2001		2.345	4.118
2002		2.369	4.201
2003		2.392	4.285
2004		2.416	4.370
2005		2.440	4.458
2006		2.465	4.547
2007		2.489	4.638
2008		2.514	4.731
2009		2.539	4.825

TABLE C-5. - ANNUAL CASH FLOWS S_j

[All costs in 1978 dollars.]

(a) Noncogeneration system

Year	Coal cost	Cost of purchased electricity	Operation and maintenance cost	Insurance and local taxes[a]	Total operating cost	Tax depreciation	Investment tax credit	Taxable income	Tax	Net cash flow
1985	1.900×10^6	2.000×10^6	800×10^6	400×10^6	5.100×10^6	1.028×10^6	1.336×10^6	6.128×10^6	$4.400 \times 10_6$	0.700×10^6
1986	1.957	2.020			5.177	.987	0	6.164	3.082	2.095
1987	2.016	2.040			5.256	.946		6.202	3.101	2.155
1988	2.076	2.061			5.337	.905		6.242	3.121	2.216
1989	2.138	2.081			5.419	.864		6.283	3.142	2.277
1990	2.203	2.102			5.505	.822		6.327	3.164	2.341
1991	2.269	2.213			5.592	.781		6.373	3.187	2.405
1992	2.337	2.144			5.681	.740		6.421	3.211	2.470
1993	2.407	2.166			5.773	.699		6.472	3.236	2.537
1994	2.479	2.187			5.866	.658		6.524	3.262	2.604
1995	2.553	2.209			5.962	.617		6.579	3.290	2.672
1996	2.553	2.231			5.984	.570		6.560	3.280	2.704
1997	2.553	2.254			6.007	.535		6.542	3.271	2.736
1998	2.553	2.276			6.029	.493		6.522	3.261	2.768
1999	2.553	2.299			6.052	.452		6.504	3.252	2.800
2000	2.553	2.322			6.075	.411		6.486	3.243	2.832
2001	2.553	2.345			6.098	.370		6.468	3.234	2.864
2002	2.553	2.369			6.122	.329		6.451	3.226	2.896
2003	2.553	2.392			6.145	.288		6.433	3.217	2.928
2004	2.553	2.416			6.169	.247		6.416	3.208	2.961
2005	2.553	2.440			6.193	.206		6.399	3.200	2.993
2006	2.553	2.465			6.218	.164		6.382	3.191	3.027
2007	2.553	2.489			6.242	.123		6.365	3.183	3.059
2008	2.553	2.514			6.267	.082		6.349	3.175	3.092
2009	2.553	2.539			6.292	.041		6.333	3.167	3.125

(b) Cogeneration system (distillate)

Year	Distillate cost	Operation and maintenance cost	Insurance and local taxes[b]	Total operating cost	Tax depreciation	Investment tax credit	Taxable income	Tax	Net cash flow
1985	3.00×10^6	950×10^6	521×10^6	4.471×10^6	1.337×10^6	3.476×10^6	5.808×10^6	0.380×10^6	-1.909×10^6
1986	3.060			4.531	1.283	0	5.814	2.097	1.624
1987	3.121			4.592	1.230		5.822	2.911	1.681
1988	3.184			4.655	1.176		5.831	2.916	1.739
1989	3.247			4.718	1.123		5.841	2.921	1.797
1990	3.312			4.783	1.070		5.853	2.926	1.857
1991	3.378			4.849	1.016		5.865	2.933	1.916
1992	3.446			4.917	.963		5.880	2.940	1.977
1993	3.515			4.986	.909		5.895	2.948	2.038
1994	3.585			5.056	.856		5.912	2.956	2.100
1995	3.657			5.128	.802		5.930	2.965	2.163
1996	3.730			5.201	.749		5.950	2.975	2.226
1997	3.805			5.276	.695		5.971	2.986	2.290
1998	3.881			5.352	.652		5.994	2.997	2.355
1999	3.958			5.429	.588		6.017	3.009	2.420
2000	4.038			5.509	.535		6.044	3.022	2.487
2001	4.118			5.589	.481		6.070	3.035	2.554
2002	4.201			5.672	.428		6.100	2.050	2.622
2003	4.285			5.756	.376		6.130	3.065	2.691
2004	4.370			5.841	.321		6.162	3.081	2.760
2005	4.458			5.929	.267		6.196	3.098	2.831
2006	4.547			6.018	.214		6.232	3.116	2.902
2007	4.638			6.109	.160		6.269	3.135	2.974
2008	4.731			6.202	.107		6.309	3.154	3.048
2009	4.825			6.296	.053		6.349	3.175	3.121

[a] $13\,364\,(0.03) = 400.$
[b] $17\,380\,(0.03) = 521.$

TABLE C-6. - INCREMENTAL CASH FLOW

[All values in 1978 dollars.]

Year	Non-cogeneration system cost	Cogeneration system cost	Incremental cash flow	Cash flow discounted at 20.5 percent
1984	13.364×10^6	17.380×10^6	-4.016×10^6	-4.016×10^6
1985	.700	-1.909	2.609	2.165
1986	2.095	1.624	.471	.324
1987	2.155	1.681	.474	.271
1988	2.216	1.739	.477	.226
1989	2.277	1.797	.480	.189
1990	2.341	1.857	.484	.158
1991	2.405	1.916	.489	.133
1992	2.470	1.977	.493	.111
1993	2.537	2.038	.499	.093
1994	2.604	2.100	.504	.078
1995	2.672	2.163	.509	.065
1996	2.704	2.226	.478	.051
1997	2.736	2.290	.446	.039
1998	2.768	2.355	.413	.0303
1999	2.800	2.420	.380	.0232
2000	2.832	2.487	.345	.0175
2001	2.864	2.554	.310	.0130
2002	2.896	2.622	.274	.0095
2003	2.928	2.691	.237	.0069
2004	2.961	2.760	.201	.0048
2005	2.993	2.831	.162	.0032
2006	3.027	2.902	.125	.0021
2007	3.059	2.974	.085	.0012
2008	3.092	3.048	.044	.0005
2009	3.125	3.121	.004	.0
				0.0006

TABLE C-7. - LEVELIZED ANNUAL ENERGY COST ANALYSIS

Variable	Numeric values	
	Noncogeneration system	Cogeneration system
Capital cost without cost of capital or escalation during construction, K, 1978 dollars	13×10^6	16×10^6
Capital cost expenditure, C, 1978 dollars	13.364×10^6	17.380×10^6
Tax depreciation life, n_T, yr	25	25
After-tax cost of capital at zero inflation, m, 1978 dollars	0.060	0.060
Capital recovery factor for after-tax cost of capital m and tax life n_T, CRF_{m,n_T}	0.0782	0.0782
Economic life of investment, n_B, yr	25	25
Capital recovery factor for after-tax cost of capital m and economic life n_B, CRF_{m,n_B}	0.0782	0.0782
Levelized depreciation factor, assuming sum-of-the-year-digits depreciations, DEP	0.626	0.626
Investment tax credit rate, c	0.10	0.20
Fixed charge rate, FCR	0.0918	0.0761
Levelized fixed charges, C x FCR, 1978 dollars	1.227×10^6	1.323×10^6

TABLE C-8. - LEVELIZED COAL COST

[See equation (19) of appendix C.]

Year	Coal cost, 1978 dollars	Present value at 0.060 after-tax cost of capital, 1978 dollars
1985	1.900×10^6	1.792×10^6
1986	1.957	1.742
1987	2.016	1.693
1988	2.076	1.644
1989	2.138	1.598
1990	2.203	1.553
1991	2.269	1.509
1992	2.337	1.466
1993	2.407	1.425
1994	2.479	1.384
1995	2.553	1.345
1996	↓	1.269
1997		1.197
1998		1.129
1999		1.065
2000		1.005
2001		.948
2002		.894
2003		.844
2004		.796
2005		.751
2006		.708
2007		.668
2008		.631
2009		.595
		$\overline{29\ 652} \times 0.0782$[a] $= 2.319 \times 10^6$

[a]$0.0782 = CRF_{0.060,25}$.

TABLE C-9. - LEVELIZED DISTILLATE AND PURCHASED ELECTICITY COST ANALYSIS

Variable	Numeric value	
	Distillate	Purchased electricity
Cost (or revenue) in year j = 0, P_0, 1978 dollars	2.941×10^6	1.980×10^6
Real fuel price escalation per year, e	0.02	0.01
Before-tax cost of capital, m'	0.060	0.060
Cost recovery factor for before-tax cost of capital m', $CFR_{m'}$	0.0782	0.0782
Capital cost without cost of capital or escalation during construction, k	0.0392	0.0495
Cost recovery factor for capital cost k, CRF_k	0.0635	0.0706
$CRF_{m'}/CRF_k$	1.2315	1.1077
Levelized cost, 1978 dollars	3.622×10^6	2.193×10^6

TABLE C-10. - LEVELIZED O&M, TAXES, INSURANCE AND ANNUAL ENERGY COSTS

[See equation (17) of appendix C.]

	Noncogeneration system	Cogeneration system
Levelized O&M, taxes and insurance		
Levelized O&M	0.800×10^6	0.950×10^6
Levelized taxes and insurance	.400	.521
Levelized annual energy cost, 1978 dollars		
Levelized fixed charges	1.227×10^6	1.323×10^6
Levelized coal cost	2.319	0
Levelized purchased electricity cost	2.193	0
Levelized distillate cost	0	3.622
Levelized O&M	.800	.950
Levelized local taxes and insurance	.400	.521
Total levelized cost	6.939×10^6	6.4316×10^6

TABLE C-11. - SUMMARY OF RESULTS FOR CASE A

Incremental rate of return, percent	20.5
Levelized energy cost, 1978 dollars:	
Noncogeneration system	6.939×10^6
Cogeneration system	6.416×10^6
Cost saving ratio	0.075
Investment ratio	1.30

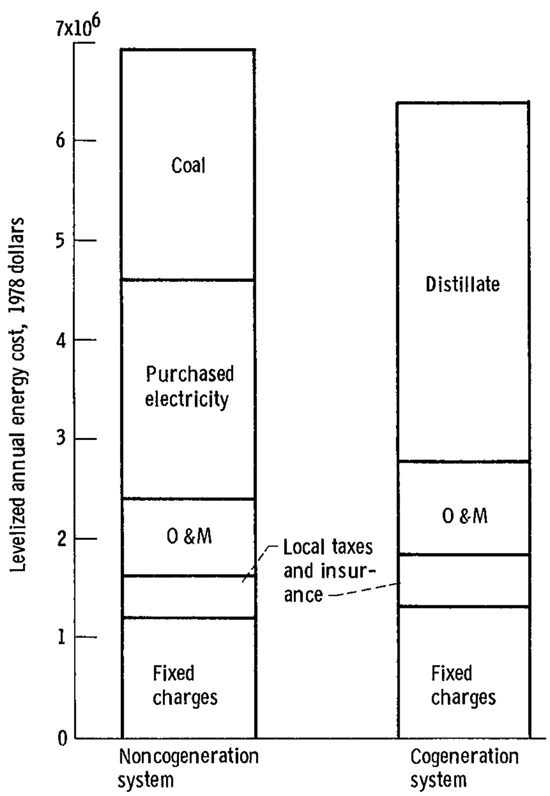


Figure C-1. - Levelized annual energy costs.

APPENDIX D

PARAMETRIC COGENERATION ANALYSIS AND DISCUSSION OF EVALUATION PARAMETERS

Raymond K. Burns

A large variety of parameters can be used to characterize cogeneration system performance and economics. Lewis specified a basic set of output parameters to be used by both contractors not only so that numerical results would be directly comparable, but also because the parameters defined by Lewis were felt to be particularly suitable for use in a study such as this one. The parameters that were emphasized in CTAS in evaluating the plant-site results were

(1) Fuel energy saving ratio, percent
(2) Emissions saving ratio, percent
(3) Operating cost saving, dollars/yr
(4) Incremental capital cost, dollars
(5) Levelized annual energy cost saving ratio, percent
(6) Return on investment, percent

These parameters are defined in section 4.3. This appendix discusses the factors affecting the cogeneration results in terms of these parameters. Energy conversion system characteristics and industry site requirements were parametrically varied to illustrate the effect in terms of these parameters.

Note that these parameters are a measure of the performance and economics of a complete cogeneration system and that the energy conversion systems are configured for cogeneration and matched to the requirements of a particular industry process according to one of the matching strategies defined in section 3.1. Comparing two cogeneration systems that use two different energy conversion systems in terms of one of these parameters might be very different from comparing the energy conversion systems themselves in terms of such parameters as system electrical efficiency or capital cost. The cogeneration parameters in the preceding list depend very heavily on (1) the cogeneration strategy; (2) the cost and performance of the supplementary boiler and the heat-recovery heat exchanger; (3) the cost and performance of the noncogeneration boiler; (4) the relative costs of fuels; and (5) the relative prices of purchased or sold electricity in addition to the energy conversion system characteristics.

D.1 FUEL ENERGY SAVING

The fuel energy saving ratio (FESR) parameter specified to measure cogeneration system performance is the fuel energy saved as compared with that required to meet the site requirements without cogeneration (refer to section 2.5).

The fuel energy in the cogeneration case is that used by the cogenerating energy conversion system plus that required at the utility if additional electricity is required or the fuel energy required by an onsite furnace or boiler if additional process heat is required. In the noncogeneration case the fuel energy is the sum of that used at the utility site to produce electricity and that used at the industrial site to produce heat. To be

consistent, when the cogeneration case involves electricity exported to the utility, the fuel energy at the utility in the noncogeneration case is adjusted to account for electricity production equal to the cogeneration case.

Because of the waste heat recovery from the onsite power system, there is usually a saving in total fuel use when cogeneration is employed as compared with the noncogeneration case, where all the electricity is generated at the utility site without waste heat recovery. The fuel saving depends not only on the conversion system electrical efficiency and the amount of its recovered waste heat, but also on the ratio of power to recovered heat and the strategy used to match these to the industrial process requirements. At the start of CTAS a parametric analysis was done to display the relationship among the conversion system efficiency, the heat recovery factor, the resulting power-to-heat ratio obtained from the conversion system, the cogeneration matching strategy used, and the fuel saving obtained. In that analysis the conversion system was characterized by its electrical efficiency η_e and a heat recovery factor AR.

Once the temperature and pressure of the heat transfer fluid (e.g., steam, hot water, or gas) are specified, the value of AR is determined from a heat balance on the energy conversion system and any heat exchangers needed to recover heat. Both contractors have provided data that can be used to determine the values of η_e and AR as a function of the process temperature requirements for each energy conversion system studied.

Cogeneration fuel saving results from recovery of heat from the energy conversion system. Therefore the maximum fuel saving is achieved when all of the site process heat is obtained by waste heat recovery from the energy conversion system that simultaneously produces the electricity used for the process. The fuel saving achievable in such a case is shown in figure D-1. For a particular energy conversion system, characterized by values of η_e and AR, the ratio of power to recovered heat is shown on the abscissa, and the fuel energy saving that would be achieved if this ratio matched that required by the process is shown on the ordinate.

If the system power-to-heat ratio does not match the site requirement and if any of the matching strategies other than match heat (while exporting power) is used, the fuel saving will be lower than shown in figure D-1.

The ranges of η_e and AR considered in figure D-1 cover the range of interest for the energy conversion systems studied in CTAS. Comparison with figure 3.2-2 shows that the range of system power-to-heat ratios also covers the range of interest for the processes studied in CTAS. As shown by the figure the energy conversion systems with higher η_e yield higher potential cogeneration fuel energy savings if matched to processes that require higher power-to-heat ratios. But higher potential cogeneration fuel savings might not be realized by more efficient energy conversion systems if the value of AR is low. Some of the systems studied in CTAS achieve high η_e by better utilizing the input heat so that the waste heat is rejected at lower temperatures. For a particular process temperature requirement a lower energy conversion heat-rejection temperature might result in significantly lower AR.

For some energy conversion systems the value of AR is very sensitive to the form and temperature of the heat transfer fluid used to provide process heat. For other systems the AR value does not change for a wide range of conditions. As an example, a diesel has appreciable heat rejection to the jacket coolant as well as to the exhaust gas. If the process heat were required in the form of pressurized hot water and the jacket coolant heat were recovered, the value of AR would be much higher than if the process heat were required in the form of high-pressure steam and only part of the exhaust gas heat were recovered (section 5.2). For a simple-cycle gas turbine with relatively high turbine exhaust temperature the fraction of waste heat recovered is constrained only by the exhaust stack acid dewpoint for a wide range of process steam pressures. If, however, a recuperator cycle were used and the exhaust gas temperature were considerably lower, the value of AR would be sensitive to process steam pressure when the minimum heat-recovery heat exchanger approach or pinch-point temperature differences became constraining. In such a case the use of a smaller recuperator, and lower electrical efficiency η_e might be desirable to increase the value of AR. Such effects are illustrated in sections 5.3 and 5.6.

Given a heat balance for a particular energy conversion system and given the form and temperature required of the process heat transfer fluid, the values of η_e and AR can be determined. Figure D-1 is useful as a first step to indicating the range of power-to-heat ratios for industries with which that system would be a good match and the corresponding potential fuel energy savings. In section 6.0 such a plot has been used for each type of energy conversion system as an initial comparison of the cogeneration performance for specific system configurations studied by each contractor.

To compare two systems that have different values of η_e and AR and hence yield different power-to-heat ratios but are applied to a common process, the effect of the matching strategy on fuel energy saving must be considered. The fuel energy saving is strongly affected by the difference between the power-to-heat ratio produced by the system and that required by the process and by the strategy used to match the power and heat requirements. The effect is illustrated in figure D-2, where the fuel energy saving is shown for two energy conversion sytems for a range of site-required power-to-heat ratios. The values of η_e and AR were chosen for these examples to yield a power-to-heat ratio of 0.2 for system A and 0.6 for system B. If the site requirement matches this, the fuel savings shown in figure D-2 agree with those shown in figure D-1. For each system, four situations are illustrated, depending on whether the site-required power-to-heat ratio is less than or greater than that produced by the systems and on whether the system is sized to produce the required power or heat. These situations are itemized in table D-1.

If the system produces a higher power-to-heat ratio than required by the process and is sized to produce the required amount of heat (situation 1), excess power is produced and the fuel saving is constant. This assumes that the excess power is exported from the site and used elsewhere.

If the system produces a higher power-to-heat ratio than required by the process and is sized to produce the required amount of power (situation 2), a supplementary furnace would be needed to provide additional heat for the process. The amount of additional fuel required for the supplementary furnace increases as the site-required power-to-heat ratio decreases relative to that produced by the system. This in the decrease in fuel energy savings shown in figure D-2. For a site requiring power-to-heat ratios less than 0.2, system B

has about the same fuel energy saving as system A when both are sized to match the required power. If sized to match heat, system B yields higher fuel saving but results in greater export power.

If the system produces a power-to-heat ratio lower than required at the site and is sized to produce the amount of required heat (situation 3), power would have to be purchased from the utility. Since the purchased power would not involve waste heat recovery, the fuel saving would again be lower than had the power-to-heat ratios matched. If the system produces the required power when the system power-to-heat ratio is lower than needed at the site (situation 4), the amount of recovered waste heat (as characterized by AR) would be more than needed by the process, so less than this amount would be recovered. This corresponds to reducing AR for constant η_e in figure D-1. This last case will yield a higher fuel energy saving than the previous case only if η_e is greater than the utility electrical efficiency. As shown by figure D-2, for power-to-heat ratios greater than 0.2, system B yields higher fuel energy savings than system A.

D.2 EMISSIONS SAVING

With onsite generation of power more fuel is used at the industrial site than in the noncogeneration case, where fuel is burned on site only to provide process heat. Therefore in most cases there is an increase in total site emissions, the amount depending on the relative amounts of fuel used, the properties of the fuels, and the combustion characteristics of the system as compared with the noncogeneration furnace. Because cogeneration results in less fuel burned at the utility site, when both the utility site and the industry site are considered, there is usually an overall reduction in emissions.

The parameter used to measure this in CTAS was analogous to the fuel energy saving ratio (i.e., the emissions saving ratio (EMSR)).

The emissions include those at the utility site and at the industrial site. This emissions saving ratio was calculated individually for sulfur dioxide, oxides of nitrogen, and particulates, as well as for the sum of all three.

In addition to the fuel energy saved, the emissions saving ratio obviously depends on the characteristics of the fuels used at the utility, in the onsite boilers with or without cogeneration, and in the onsite energy conversion system. It also depends on the cogeneration matching strategy since this strongly affects the relative amounts of fuels used in the onsite system, in any onsite furnaces or boilers, and at the utility.

Because it was assumed that the utility used coal, many of the cogeneration cases calculated in CTAS that used liquid fuels yielded impressive emissions saving ratios. Those cases that used distillate fuels generally yielded the highest values. The emissions saving ratio depends heavily on the type of fuel used in the noncogeneration onsite boiler.

To illustrate these effects, the emissions saving ratio and site emissions ratios were calculated for the cogeneration cases of figure D-2. (As in fig. D-2 each system was considered for a range of site power-to-heat ratios

using the matching strategies itemized in table D-1.) System B uses a coal-derived residual fuel and system A uses coal. The emissions characteristics of the onsite system, of onsite boilers, and of the utility powerplant were assumed to equal the emissions guidelines for the corresponding fuels (section 4.1). The ratio of site emissions with cogeneration to those without cogeneration is shown in figure D-3 and the emissions saving ratio defined above is shown in figure D-4. In each case the results are based on two assumptions concerning the fuel used in the noncogeneration onsite boiler. In part (a) it is assumed to be a coal-derived residual fuel; in part (b) it is assumed to be coal. When a supplementary boiler is needed for the cogeneration case, it is assumed to use the same fuel used by the onsite system.

The site emissions in figure D-3 are greater for the cogeneration case than for the noncogeneration case. The site emissions ratios for the two example power systems at their respective system power-to-heat ratios of 0.2 and 0.6 are approximately the same, even though the emissions from system B, on a pounds-per-unit-of-fuel-burned basis, are lower than those from system A, which burns coal. The reason for this is that more fuel is burned in system B than in system A per unit of site heat required because the power-to-heat ratio of system B is higher than that of system A. When the match-heat strategy is selected, varying the site power-to-heat ratio has no effect on the site emissions ratio since the ratio of cogeneration-to-noncogeneration site fuel remains constant. When the match-power strategy is assumed, however, the site emissions ratio increases with increasing site power-to-heat ratio because the ratio of system fuel to noncogeneration fuel also increases. The site emissions ratio for the case where coal is used as the noncogeneration onsite boiler fuel is lower (part (b)) than the site emissions ratio when a coal-derived residual fuel is used for the noncogeneration boiler (part (a)). This is due to the increased noncogeneration site emissions when coal is used in the onsite boiler.

The emissions saving ratios for the two example cogeneration cases are shown in figure D-4. In part (a) the emissions saving ratio for system A is negative because of the relatively higher emissions when burning coal in the system as compared with burning the relatively cleaner residual fuel in the noncogeneration onsite boiler and coal at the utility. The higher emissions savings achieved with system B as compared with system A are due to the higher fuel energy savings achieved by system B (fig. D-2) and to the lower emissions levels when burning the coal-derived residual fuel. The cogeneration system using the liquid fuel (system B) yields impressive emissions saving ratios primarily because coal is used by the utility in the noncogeneration case. In figure D-4(b) the emissions saving ratios for both examples are higher than those shown in part (a) because of the relatively higher noncogeneration emissions when using coal in the onsite boiler. Generally the shape of the curves shown in figure D-4 for the emissions saving ratio resembles the shape of the curves shown in figure D-2 for the fuel energy saving ratio.

D.3 OPERATING COST SAVINGS

Operating cost is defined as the sum of yearly expenditures for fuel, electricity, and other expendables such as water, lime, or limestone and operating labor and maintenance costs. The operating cost savings due to cogeneration are dominated by the relative cost of the fuel required for the cogeneration energy conversion system, the cost of the boiler fuel saved

because of conversion system waste heat recovery, and the cost of the electricity that no longer is purchased from the utility. In addition to being sensitive to the same things to which the fuel savings are sensitive, the operating cost savings depend on the fuel and electricity prices. In general those systems that used coal achieve the highest operating cost savings in CTAS for any specific process, and those that use distillate fuel achieve the lowest operating cost savings.

The operating cost savings also depend on the fuel assumed to be used in the onsite noncogeneration process steam boiler. In some industry processes with a very low site-required power-to-heat ratio, when it was assumed that the noncogeneration onsite boiler uses residual fuel, some coal-fired conversion systems yield positive operating cost savings even though the fuel energy savings are very low or even negative. The operating cost savings are not the result of cogeneration and heat recovery but result from the switch to cheaper coal in the cogeneration case rather than the residual fuel used in the noncogeneration case.

Because the operating cost savings depend on the relative fuel and electricity costs, they also depend heavily on which cogeneration strategy is used. This is true for export situations since one CTAS ground rule was that electricity exported to the grid would yield an income equal to 60 percent of the purchase price of a corresponding amount of electricity.

The effects on operating costs savings are shown in figure D-5 for the two example energy conversion systems. Operating cost savings are shown as a function of site-required power-to-heat ratio and matching strategy. In part (a) a coal-derived residual fuel is burned in the noncogeneration onsite boiler, and in part (b) coal is burned in this boiler. The operating costs for the noncogeneration and cogeneration cases were estimated by assuming the same electricity and fuel costs that were used in CTAS (section 4.1) and by using estimated operation and maintenance (O&M) costs for typical coal-fired (system A) or coal-derived-residual-fueled (system B) energy conversion system and boilers. The site power requirement was assumed to be fixed at 20 MW electric, with the heat requirement varying with different site-required power-to-heat ratios.

System A is shown in figure D-5 to have higher operating cost savings than system B at low site-required power-to-heat ratios because the coal used in system A costs less than the residual fuel used in system B. In part (a) for system A using a match-power strategy with the site-required power-to-heat ratio less than that produced by the system (situation 1), the operating cost savings increase as shown. For the match-power strategy the noncogeneration onsite boiler fuel use and cogeneration supplementary boiler fuel use both increase with decreasing site-required power-to-heat ratio. However, the cogeneration supplementary boiler for system A burns coal, which is less expensive than the residual fuel burned in the noncogeneration boiler. Hence the net result is an increase in operating cost. For system B the operating cost saving remains constant with decreasing site-required power-to-heat ratio because both the noncogeneration onsite boiler and the cogeneration supplementary boiler burn the same residual fuel at the same cost. The operating cost saving shown in this situation for system B results from a saving in purchased electricity cost and boiler fuel cost at a site power-to-heat ratio of 0.6. For the same situation where coal is assumed to be used in the

noncogeneration boiler (part (b)) the operating cost saving for system A remains constant with decreasing site-required power-to-heat ratio when the match-power strategy is used. The reason is that both the noncogeneration and cogeneration boilers use the same fuel (coal) with the same increase in the amount of fuel burned as the site-required power-to-heat ratio is decreased. However, for system B the operating cost saving decreases with decreasing power-to-heat ratio because the residual fuel burned in the cogeneration supplementary boiler costs more than the coal burned in the noncogeneration boiler.

When the match-power strategy is assumed and the site-required power-to-heat ratio is greater than the system power-to-heat ratio (situation 4), the operating cost saving decreases for both systems A and B in figure D-5. More recoverable waste heat is produced by the system than can be used by the process, and this results in decreasing heat recovery as the site-required power-to-heat ratio is increased. The only cogeneration fuel used in this case is that for the system, and the ratio of cogeneration fuel to site power required remains constant in this power-to-heat ratio range. However, for the noncogeneration case the ratio of the onsite noncogeneration boiler fuel use (and cost) to the site power required decreases with increasing site-required power-to-heat ratio, and this results in a decrease in operating cost savings.

When the match-heat strategy is assumed and the site-required power-to-heat ratio is less than that produced by the system (situation 1), the operating cost saving increases for system A in both parts of figure D-5. This situation involves the export of electricity from the plant site, with increasing amounts of power being exported as the site-required power-to-heat ratio is decreased. As the site-required power-to-heat ratio is lowered, both the noncogeneration onsite boiler and cogeneration system fuel use and cost increase relative to the site power required. However, the revenue from the sale of excess electricity (at 60 percent of the selling price to the industrial site) results in an overall increase in operating cost savings. This is also true with system B when a coal-derived residual fuel is used in the noncogeneration onsite boiler (fig. D-5(a)). However, when coal is used in the noncogeneration onsite boiler (fig. D-5(b)), the operating cost savings decrease because this system uses the more expensive residual fuel instead of the coal used in the noncogeneration onsite boiler.

The last matching strategy involves matching the heat requirement of the process when the site-required power-to-heat ratio is greater than that produced by the system (situation 3). For both system A and B the operating cost savings decrease with increasing site-required power-to-heat ratio because of the continuously increasing requirement (and cost) for imported electricity that must be purchased from a utility. The operating cost savings are larger for both systems when coal-derived residual fuel (fig. D-5(a)) is used in the noncogeneration onsite boiler instead of coal (fig. D-5(b)) because of the higher noncogeneration fuel cost when burning the residual fuel.

D.4 INCREMENTAL CAPITAL COST

The incremental capital cost is defined as the difference between the capital cost of the cogeneration system and that of the onsite boiler in the noncogeneration case. Comparing two different energy conversion systems configured for cogeneration for a particular process in terms of cogeneration

incremental capital cost might yield a much different impression than would comparing the corresponding conversion system specific costs (i.e., in dollars per kilowatt electric). The cogeneration cost depends not only on the specific costs of the conversion system and boiler, but also on their relative sizes, which in turn are determined by the cogeneration matching or sizing strategy used. (The cogeneration cost also includes heat-recovery heat exchangers.) The cogeneration capital cost strongly depends on the relationship between the power-to-heat ratio of the conversion system and the power-to-heat ratio required by the process. And of course it depends on the type of fuel used for the noncogeneration boiler since this affects the boiler specific cost.

The incremental capital costs for the two example cogeneration systems are shown in figure D-6 for various site power-to-heat ratios and cogeneration matching strategies. The effect of using coal or a coal-derived residual fuel in the noncogeneration onsite boiler is also illustrated. The capital cost models used for these calculations were developed from capital cost data estimated in CTAS for typical coal-fired and residual-fueled cogeneration systems along with capital costs estimated for coal-fired and residual-fueled noncogeneration onsite boilers and cogeneration supplementary boilers. Results are shown for system A in figure D-6(a); and for system B, in figure D-6(b). The site power requirement is assumed to be 20 MW electric, with the site heat requirement varying with the site-required power-to-heat ratio.

The incremental capital costs are higher for the cogeneration system when coal-derived residual fuel is used in the onsite noncogeneration boiler because of the lower capital cost of such a boiler as compared with a coal-fired boiler. For the match-heat strategy the incremental capital costs increase as the site-required power-to-heat ratio decreases relative to the system power-to-heat ratio (situation 1). In these situations the system size increases and this results in larger capital costs for the cogeneration system (export of power occurs). Likewise, as the site-required power-to-heat ratio increases relative to that produced by the system and a match-heat strategy is assumed (situation 3), the incremental capital costs decrease because the system size and cost decrease (import of power occurs).

As shown in figure D-6(a) the incremental capital costs are always higher for the match-power strategy using system A when the site-required power-to-heat ratio is different from the system power-to-heat ratio. When the site-required power-to-heat ratio is less than that of the system (situation 2), the additional cost of a supplementary boiler results in higher incremental capital cost. When the site-required power-to-heat ratio increases relative to that of the system (situation 4), the incremental capital cost increases because of the decrease in size requirement (and capital cost) for a noncogeneration onsite boiler. This same trend is shown in part (b) for system B when the noncogeneration onsite boiler uses coal-derived residual fuel. The increase in the incremental capital cost is not as great as shown for system A. When coal is used in the noncogeneration onsite boiler, the incremental capital costs for the cogeneration system decrease when the site-required power-to-heat ratio is less than that of the system because the capital cost of this liquid-fueled boiler is lower than that of the noncogeneration coal-fired onsite boiler.

Comparing the incremental capital costs for systems A and B shows their respective system power-to-heat ratios of 0.2 and 0.6. System B has a lower incremental capital cost than system A because it uses coal-derived residual fuel, which requires less fuel handling and waste handling and has lower heat source equipment costs and installation costs than the coal-fired system A. This is more clearly illustrated in figure D-7, where the incremental capital cost is shown for both systems using coal-derived residual fuel in the noncogeneration onsite boiler. Also shown are the system costs at a site-required power-to-heat ratio of infinity (the asymptotes), that is, when the systems are being used strictly as electricity producers and cogeneration (waste heat recovery) is not taking place. Again, this illustrates the higher capital costs of the coal-fired system A as compared with the liquid-fueled system B. However, when assuming the match-heat strategy and comparing the costs at the same site-required power-to-heat ratio, the incremental capital costs are approximately the same because to meet the same site heat requirements, the systems are sized differently according to their different electrical efficiency and heat recovery characteristics.

D.5 LEVELIZED ANNUAL ENERGY COST SAVINGS

Having defined operating cost savings and incremental capital cost, two parameters were used to combine these quantities to measure the economic benefits of a cogeneration system (operating cost saving) against the capital investment (capital cost) needed to achieve those benefits. One of these parameters is the levelized annual energy cost savings. Levelized annual energy cost (LAEC) is defined as the minimum constant net revenue required each year of the project life to meet the energy-related expenses of the industrial plant, including fuel, electricity, and operating costs, the cost of money, and the recovery of the initial investment. A levelized annual energy cost saving ratio (LAECSR) is defined in section 2.5.

Items considered in the annual energy cost include fixed capital charges (including cost of debt and return on equity); fuel costs; operation and maintenance costs; the costs for purchased electricity, if required; and credits for the sale of electricity, if excess is generated by the system. This is an investment analysis approach commonly used by electric utilities. However, the methodology is also applicable to industrial firms.

In most cases the levelized annual energy cost is dominated by operating costs with fixed capital charges amounting to less than 20 percent of the total levelized annual energy cost. The levelized annual energy cost savings therefore are generally sensitive to the same factors as are the operating cost savings. However, in comparing alternative energy conversion systems, capital cost is still an important factor. Because it includes the effects of capital costs, the levelized annual energy cost sometimes yields a different comparison of cogeneration strategies than does the operating cost savings.

The levelized annual energy cost saving ratio is shown in figure D-8 for the two example cogeneration systems as a function of site-required power-to-heat ratio and cogeneration matching strategy. In part (a) coal-derived residual fuel is used in the noncogeneration boiler, and in part (b) coal is used in that boiler. The LAECSR is larger in part (a) for both systems because of the higher noncogeneration levelized annual energy cost when using the more expensive coal-derived residual fuel. Also the LAECSR is larger at relatively

small site-required power-to-heat ratios for system A because the less expensive coal is used in the system and supplementary boilers. System B achieves a higher LAECSR at the relatively higher site-required power-to-heat ratios because of its better cogeneration match with these processes.

When the match-power strategy is assumed, the LAECSR always decreases when the site-required power-to-heat ratio is varied from that produced by the system even though in some cases shown in figure D-5 the operating cost saving increases or remains constant. The LAECSR decreases because, as shown in figure D-6, the incremental capital cost increases as the site-required power-to-heat ratio is changed from that produced by the system. When the match-heat strategy is used, the LAECSR also decreases for site-required power-to-heat ratios other than the system power-to-heat ratio with one exception. Generally, when the system is sized such that export of power occurs, operating cost savings increase because of the revenue achieved from the sale of electricity, but capital cost also increases because of the larger system size. In most cases the larger capital cost of the system negates the increase in operating savings caused by the sale of electricity, with the overall result being a decrease in LAECSR. If a higher selling price for exported electricity were assumed, these cases might show more promising LAECSR. The one exception to this stated generalization is shown in figure D-8(a), where for the match-heat strategy with export of power (situation 1) the LAECSR increases for system A as the site-required power-to-heat ratio is decreased relative to the system power-to-heat ratio. This exception is due to the use of the more expensive coal-derived residual fuel in the noncogeneration onsite boiler.

D.6 RETURN ON INVESTMENT

Another parameter that is used to measure the benefits of a cogeneration system versus the capital investment to achieve those benefits is the return on investment. Return on investment (ROI) is defined as the rate that equates the present value of all future cash flows with the initial capital investment. The ROI's were based on the incremental investment required for a cogeneration system relative to the noncogeneration case. Cash flows were also incremental values relative to noncogeneration. The ROI's were calculated on an inflation-free, after-tax basis and as such represent a conservative estimate of the economic attractiveness of the cogeneration systems. ROI is frequently used by industry as one of the prime measures of the economic merit of a proposed venture.

It was illustrated in section 3.0 that ROI can be expressed as a function of a simple payback period, which is the number of years it takes to recover the initial incremental capital investment through yearly operating cost savings. Like incremental capital cost and operating cost saving, the ROI for a particular cogeneration case is a function of the cogeneration matching strategies, the site-required power-to-heat ratio, and the type of fuel burned in the noncogeneration onsite boiler. The incremental capital cost as a function of yearly operating cost saving is shown in figure D-9 for the two example cogeneration systems, with lines of constant ROI indicated. These parameters are shown for all of the cogeneration matching strategies mentioned previously. The arrows indicate the direction of increasing site-required power-to-heat ratio for each matching strategy. In figure D-9(a) coal-derived residual fuel is burned in the noncogeneration onsite boiler; in figure D-9(b) coal is burned in that boiler.

Generally, the examples shown in figure D-9(b) achieve a higher range of ROI than those shown in part (a). Although the operating cost saving is lower in part (b), the incremental capital cost is also substantially lower because of the higher noncogeneration onsite boiler capital costs associated with burning coal.

In figure D-9(a) the maximum ROI for system B is attained when the site-required power-to-heat ratio exactly matches that of the system. When the site-required power-to-heat ratio is different from that produced by system B, the ROI decreases for both the match-power and match-heat strategies. The ROI for system A also decreases when the site-required power-to-heat ratio is varied from that produced by the system and the match-power strategy is assumed (situations 2 and 4). When the match-heat strategy is used with system A, the ROI decreases when the site-required power-to-heat ratio is greater than the system power-to-heat ratio (i.e., when electricity is imported - situation 3). When the site-required power-to-heat ratio is less than that of system A (i.e., when electricy is exported - situation 1), the ROI increases slightly.

In figure D-9(b) the ROI's increase for system B when the match-power strategy is assumed and the site-required power-to-heat ratio is less than that produced by the system (resulting in the use of an auxiliary boiler - situation 2) and when the match-heat strategy is used and the site-required power-to-heat ratio is greater than that of the system (i.e., when electricity is imported - situation 3). The maximum ROI system is attained when the site-required power-to-heat ratio exactly matches that of the system.

TABLE D-1. - POWER SYSTEM - SITE MATCHING STRATEGIES

	Situation	Strategy	Comment
1	$(P/Q)_{site} < (P/Q)_{system}$	Match heat	Export excess power
2	$(P/Q)_{site} < (P/Q)_{system}$	Match power	Auxiliary boiler
3	$(P/Q)_{site} > (P/Q)_{system}$	Match heat	Import power
4	$(P/Q)_{site} > (P/Q)_{system}$	Match power	Recover only part of waste heat

[a]Where P denotes power and Q denotes heat.

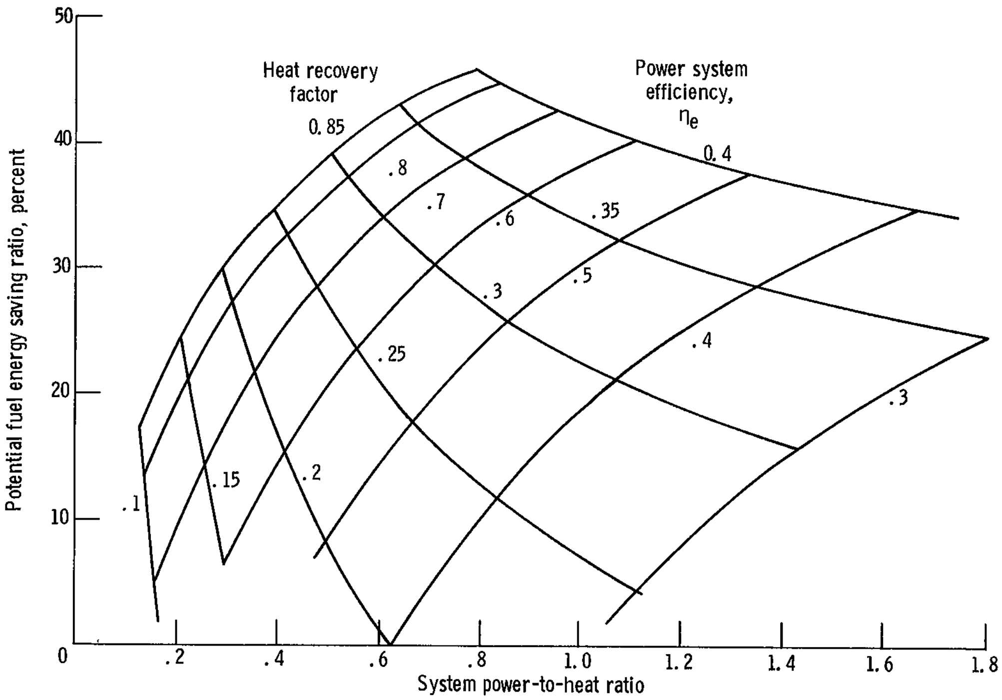
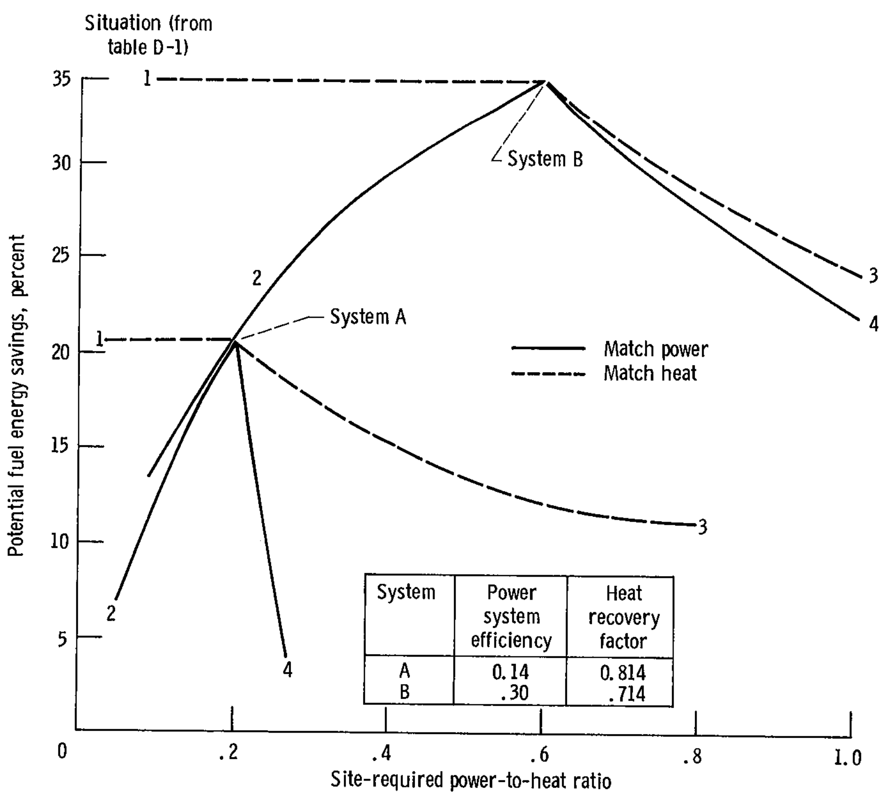
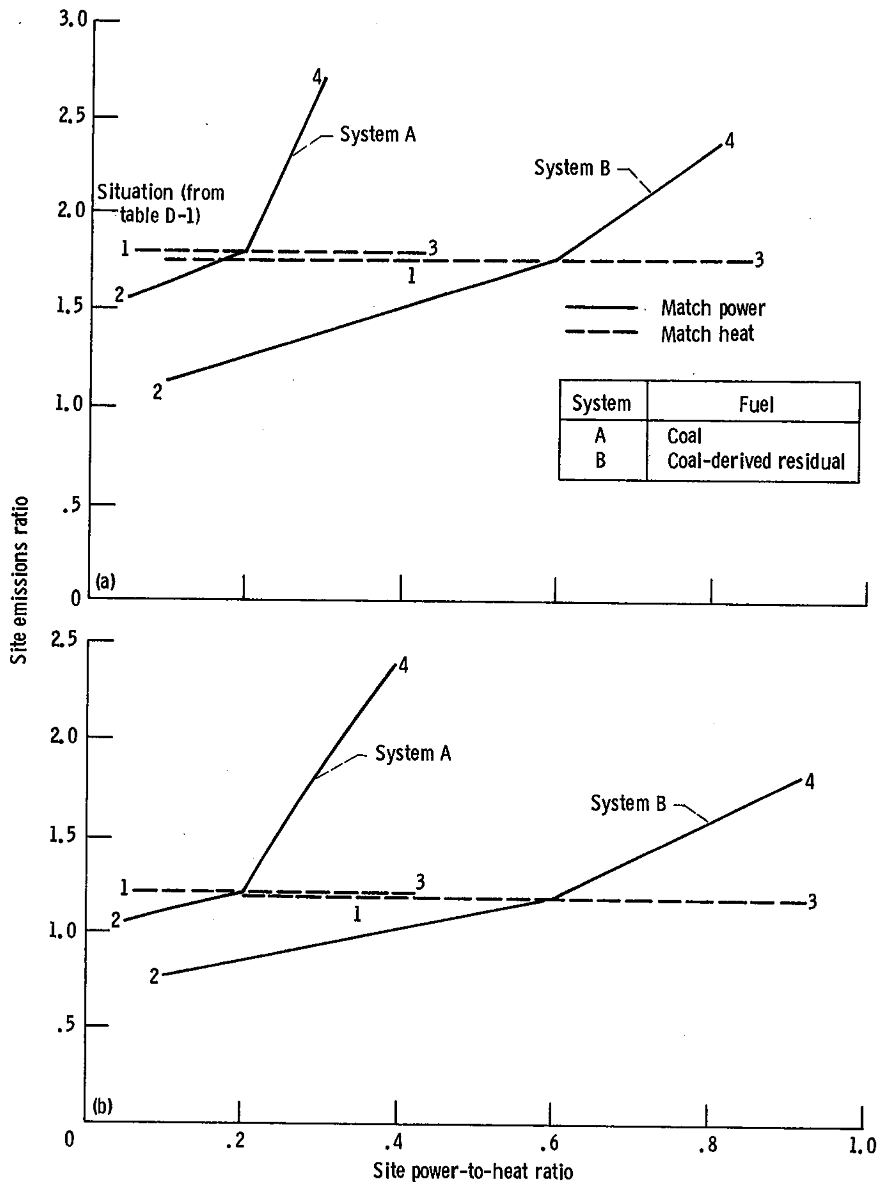


Figure D-1. - Potential fuel energy savings with cogeneration systems. For noncogeneration case: boiler efficiency, 85 percent; utility efficiency, 32 percent.



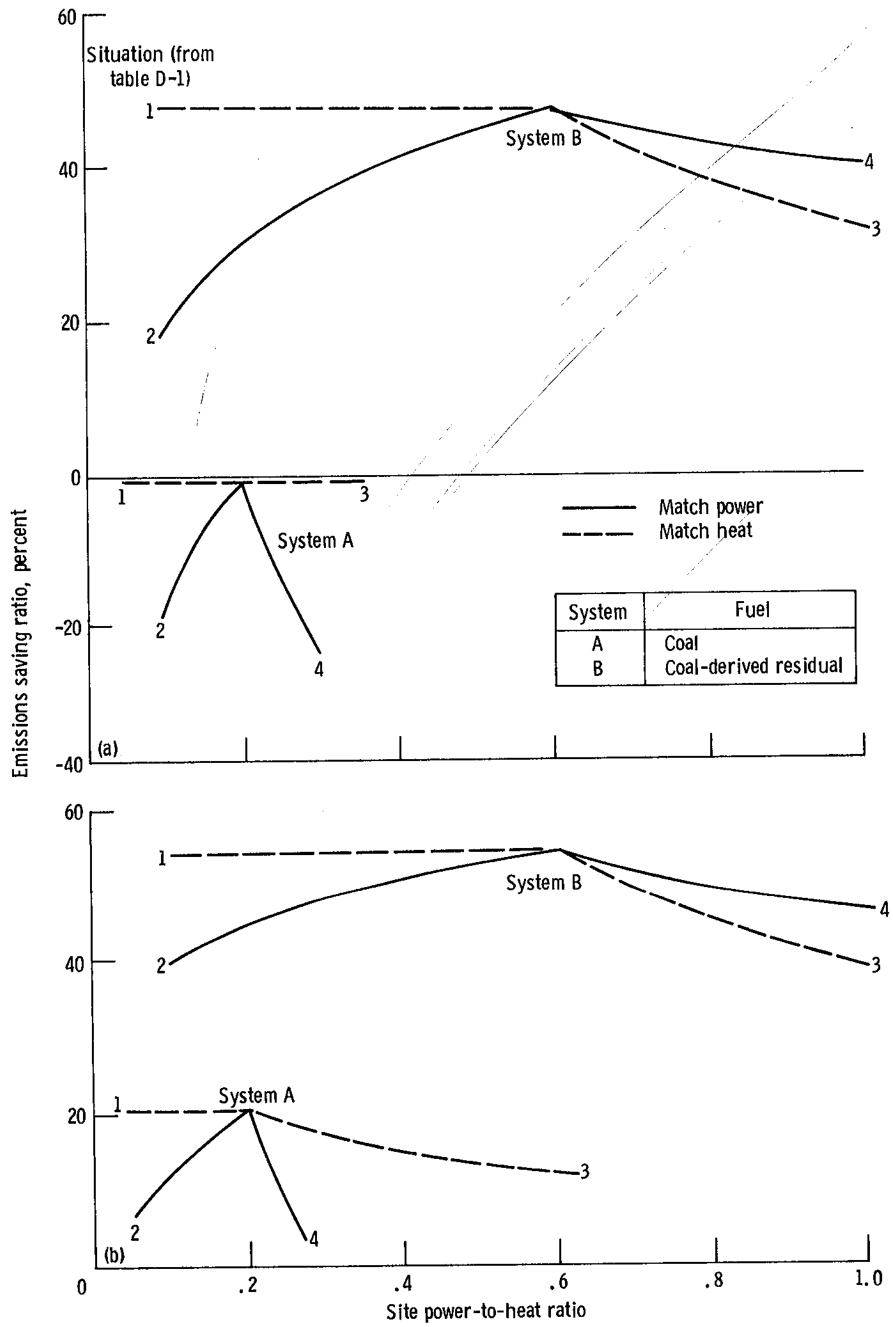
System	Power system efficiency	Heat recovery factor
A	0.14	0.814
B	.30	.714

Figure D-2. - Potential fuel energy savings for example energy conversion systems, as a function of site power-to-heat ratio and strategy used to match power and heat requirements.



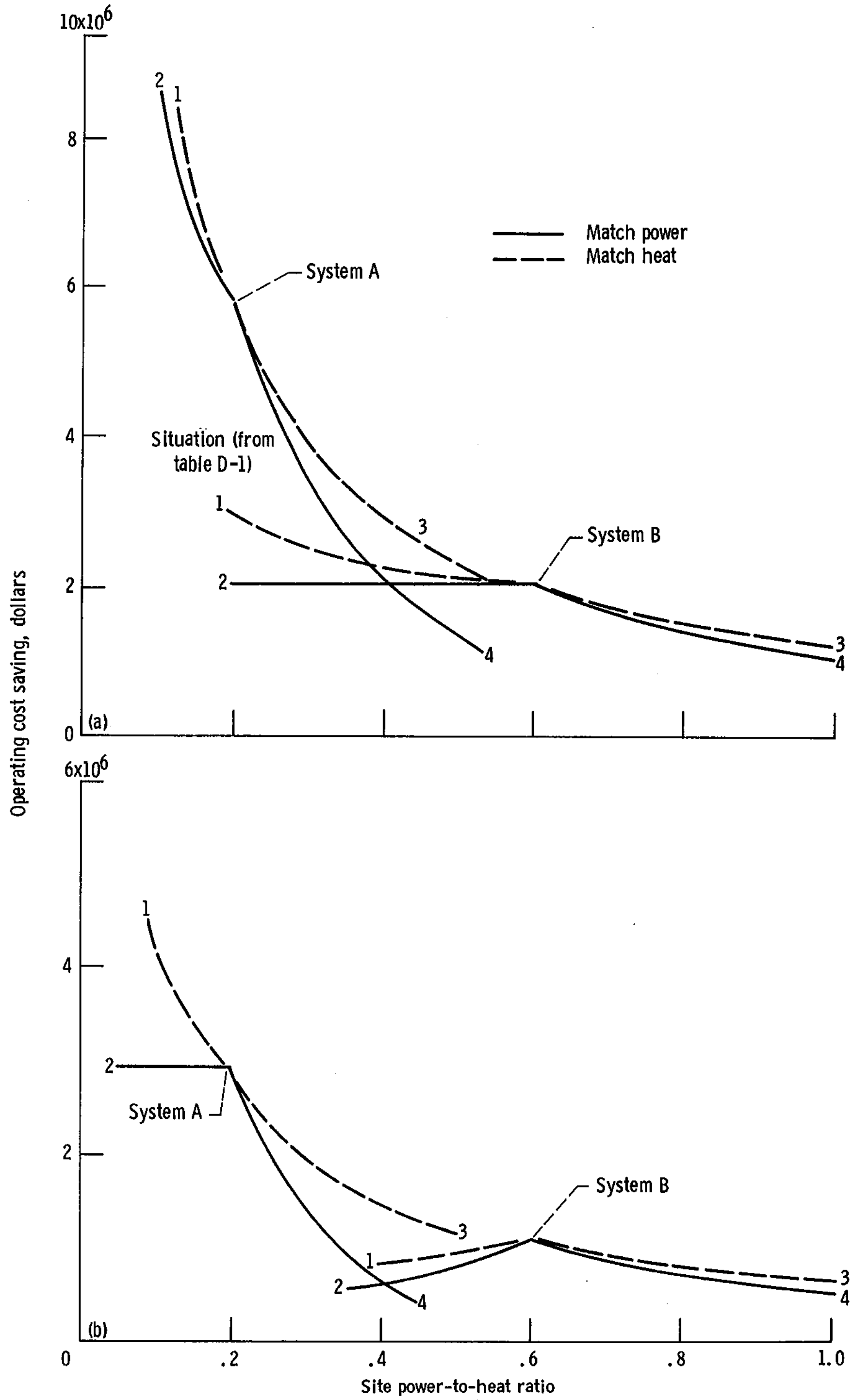
(a) Noncogeneration fuel, coal-derived residual.
(b) Noncogeneration fuel, coal.

Figure D-3. - Site emissions ratio for example energy conversion systems, as a function of site power-to-heat ratio and strategy used to match power and heat requirements.



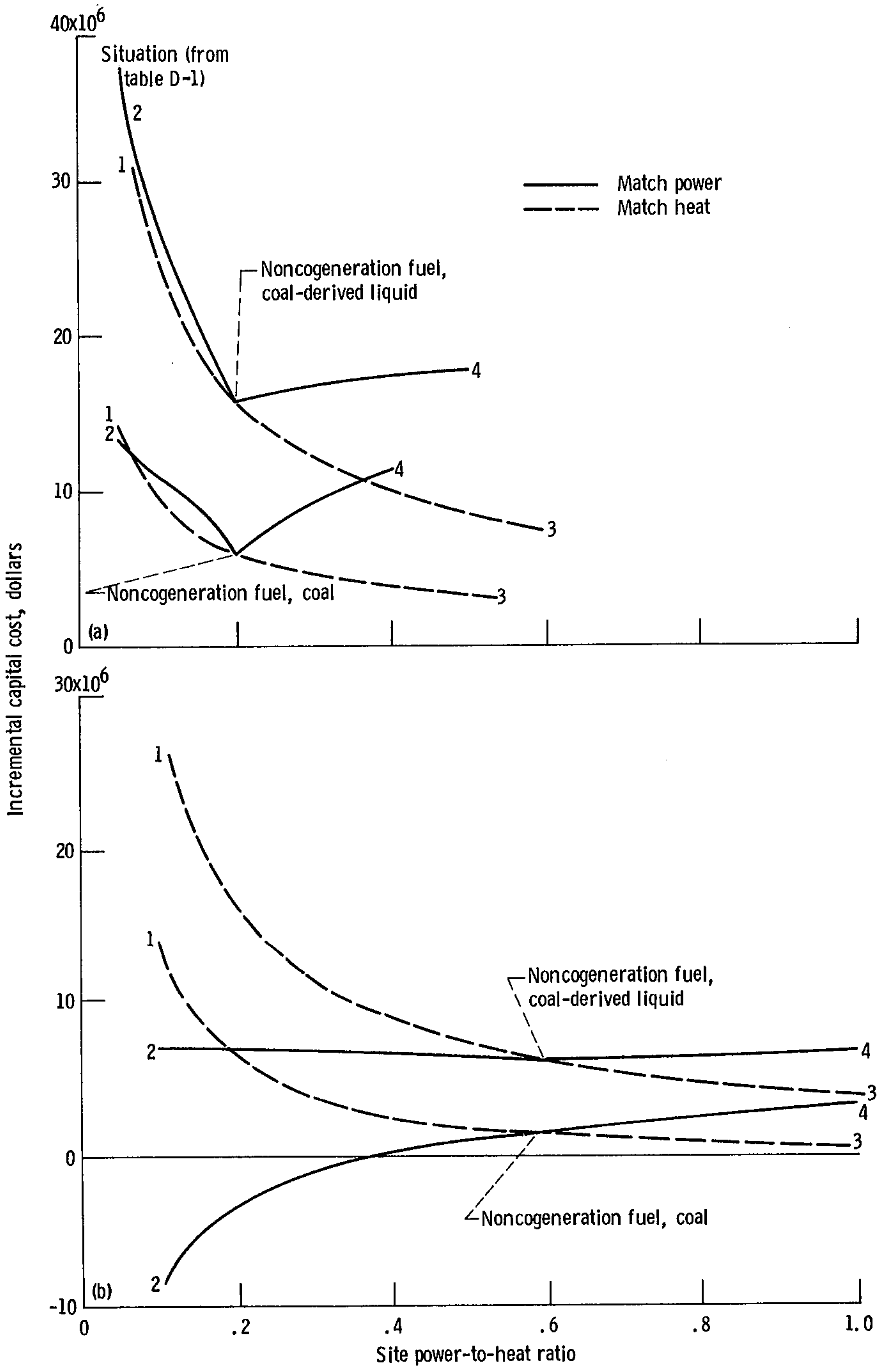
(a) Noncogeneration fuel, coal-derived liquid.
(b) Noncogeneration fuel, coal.

Figure D-4. - Emissions saving ratios for example energy conversion systems, as a function of site power-to-heat ratio and strategy used to match power and heat requirements.



(a) Noncogeneration fuel, coal-derived liquid.
(b) Noncogeneration fuel, coal.

Figure D-5. - Operating cost savings for example energy conversion systems, as a function of site power-to-heat ratio and strategy used to match power and heat requirements.



(a) System A; coal fuel.
(b) System B; coal-derived liquid fuel.

Figure D-6. - Incremental capital cost for example energy conversion systems, as a function of site power-to-heat ratio and strategy used to match power and heat requirements.

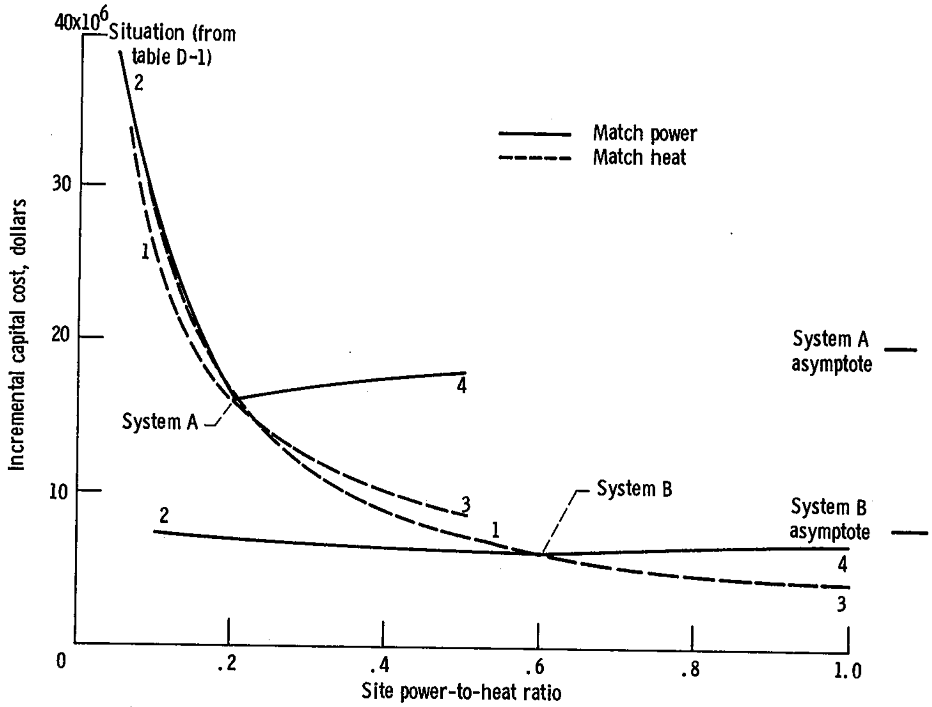
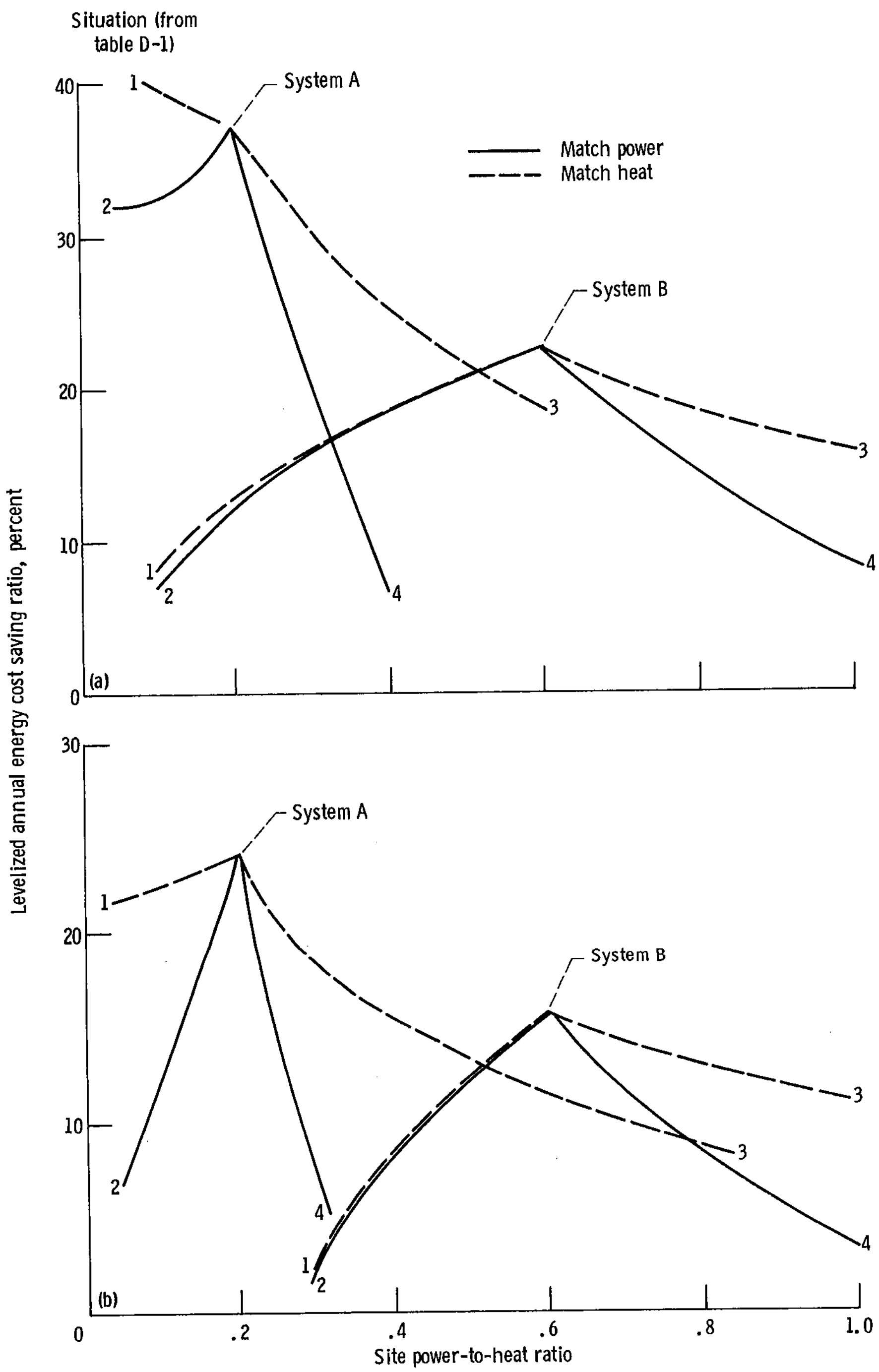
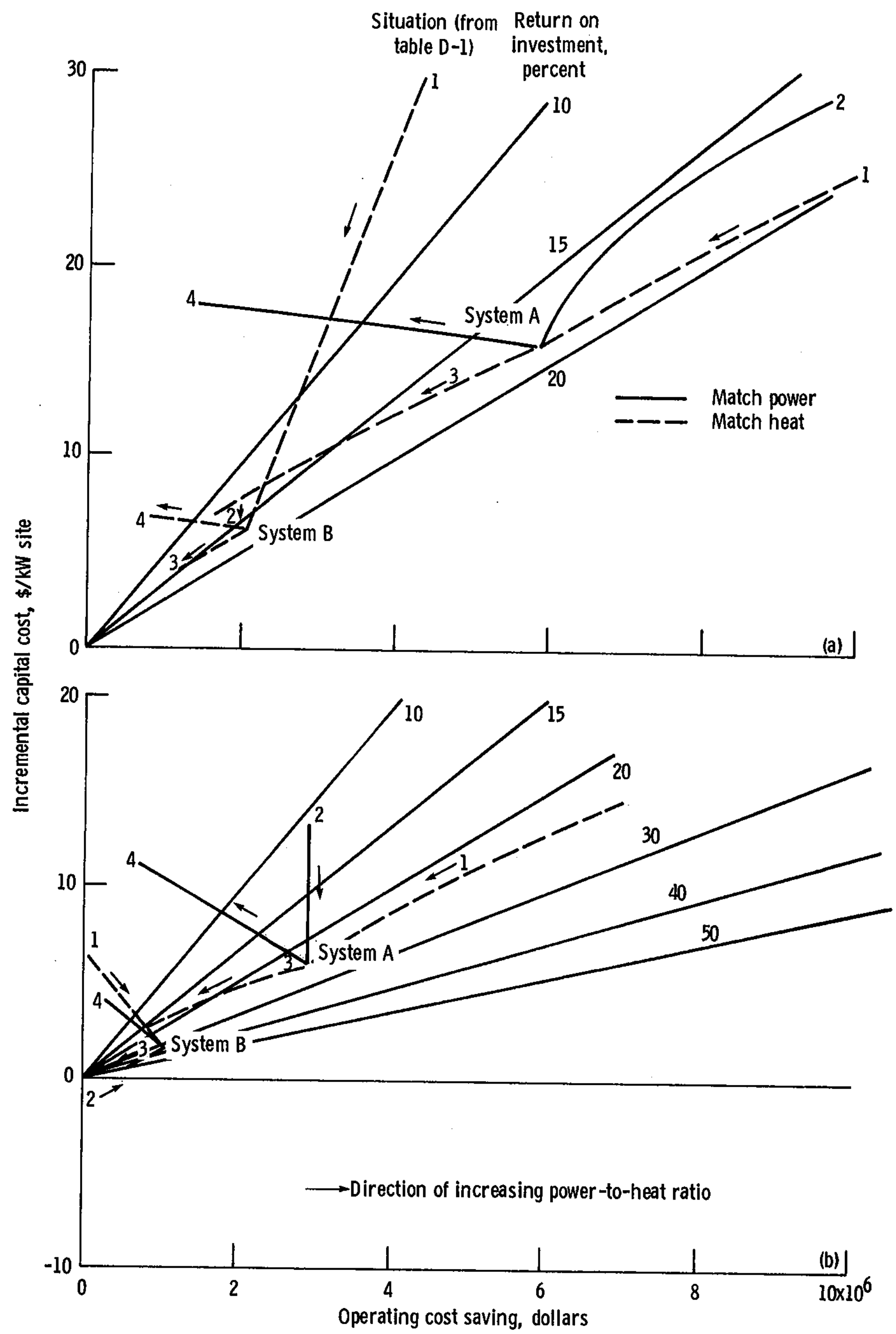


Figure D-7. - Incremental capital cost as a function of site power-to-heat ratio for example energy conversion systems using coal-derived liquid noncogeneration fuel.



(a) Noncogeneration fuel, coal-derived liquid.
(b) Noncogeneration fuel, coal.

Figure D-8. - Levelized annual energy cost saving ratio for example energy conversion systems, as a function of site power-to-heat ratio and strategy used to match power and heat requirements.



(a) Noncogeneration fuel, coal-derived liquid.
(b) Noncogeneration fuel, coal.

Figure D-9. - Return on investment for example energy conversion systems, as a function of site power-to-heat ratio and strategy used to match power and heat requirements.

APPENDIX E

SENSITIVITY OF RESULTS TO CHANGES IN FUEL AND ELECTRICITY PRICES

Raymond K. Burns

Sample results for two conversion systems in two processes are used in this appendix to illustrate the effects of variations in fuel and electricity prices on the relative economics of different cogeneration systems. These parameters represent the area where the greatest uncertainty is believed to exist in the CTAS ground rules, and it is these parameters that were found in the sensitivity analyses to have the greatest effect on the study results. Keep in mind that the sensitivities are strongly dependent on the characteristics of the particular process plant, the energy conversion system being considered, the cogeneration strategy employed, and other factors. The results presented here are only for illustration. Results of the detailed sensitivity analyses performed are presented in the detailed NASA and contractor CTAS final reports.

The writing paper mill and the chlorine plant defined by GE (as shown in table 4.4-1) are the two industrial processes that are used in the example. The power-to-heat ratio for the writing paper mill is relatively low (0.22) and as a result, when many of the advanced energy conversion systems are matched to that process by using the match-heat strategy, excess electricity is generated.
An advanced gas turbine burning coal-derived residual fuel is one example of such a system. That case is plotted in figure E-1(a), as is the case for the same conversion system applied to the same writing paper mill by using the match-electricity strategy. In the match-electricity case a supplementary boiler is required to make up the deficit in process heat from the conversion system. Also plotted in figure E-1(a) is a coal-fired steam system using an AFB. The power-to-heat ratio of this system at the required conditions is slightly lower than the power-to-heat ratio of the writing paper mill. In this instance the heat requirement is matched and a small amount of electricity is purchased from a utility.

The coordinates of figure E-1 are incremental capital cost and annual operating cost savings. The use of plots on these coordinates to compare the economic attractiveness of cogeneration systems is discussed in appendix B. The various types of horizontal lines shown going both left and right from each of the base points represent the changes in operating cost savings for specific variations in fuel and electricity prices.

Looking first at the gas turbine without export, note that the ROI for the base case is 30 percent. As the price of purchased electricity increases, the operating cost savings increase, as shown by the horizontal solid lines, and result in an increase in ROI. This change is due to the operating costs for the noncogeneration case increasing with the electricity price increase while the operating costs for the cogeneration case, which neither imports nor exports electricity, are unaffected by the price change. As the price of liquid fuel is varied, as represented by the horizontal short-dashed lines, operating cost savings vary inversely since more liquid fuel is being used on site in the cogeneration case (in both the conversion system and the supplementary boiler) than in the noncogeneration case. For this particular combination of conversion system, fuel, and process the change in operating cost

savings for a given percentage variation in liquid-fuel price is about half the change resulting from the same percentage variation in electricity price and is in the opposite direction. Since both the noncogeneration and cogeneration cases use liquid fuel, variations in coal price have no direct effect.

Next we look at the same liquid-fueled gas turbine, but this time in a match-heat strategy allowing the export of electricity. Because the gas turbine has a much higher power-to-heat ratio than that required by the process, a large amount of electricity is available for export when the process heat demand is met by heat recovery from the turbine. Note that the ROI for this base case is 24 percent as compared with 30 percent for the nonexport case. The effects of variations in liquid-fuel prices and purchased electricity prices are larger in absolute magnitude because of the increased size of the cogeneration system, but the effect on ROI is very similar to that in the nonexport case. An additional sensitivity parameter, the price received by the cogenerator for exported electricity, is introduced in this case. The base export price used in CTAS was 60 percent of the price paid by the industrial owner to purchase electricity from the utility grid. There is considerable uncertainty in this value, and the sensitivity of results for this case to variations in the export price are indicated by the heavy, long-dashed horizontal line. If the export price was increased to about 80 percent of the purchase price of electricity, the ROI for the export case would equal the ROI for the nonexport case. Above the 80 percent value the export case would have a higher ROI than the nonexport case. Export generally resulted in increasing energy savings, but at the 60 percent export sale price it reduced the ROI. The economics are significantly improved as the export price approaches the purchase price of electricity.

The remaining case plotted in figure E-1(a) is the steam system using an AFB furnace. The effect of varying the purchase price of electricity is very similar to that in the two previous cases. However, the effect of varying the liquid-fuel price is the opposite of that for the liquid-fueled system. The operating costs vary with the liquid-fuel price for the noncogeneration case, which burns liquid fuel, but the operating costs do not change for the coal-burning cogeneration case. The result is that, when different liquid-fuel prices are assumed, the relative comparison of coal-fired and liquid-fueled systems can change significantly. The effects of variations in the assumed coal price are shown by the dot-dashed line in figure E-1(a) for the steam turbine/AFB system. The effect is similar in magnitude but opposite in direction to the effect of the same percentage change in liquid-fuel price.

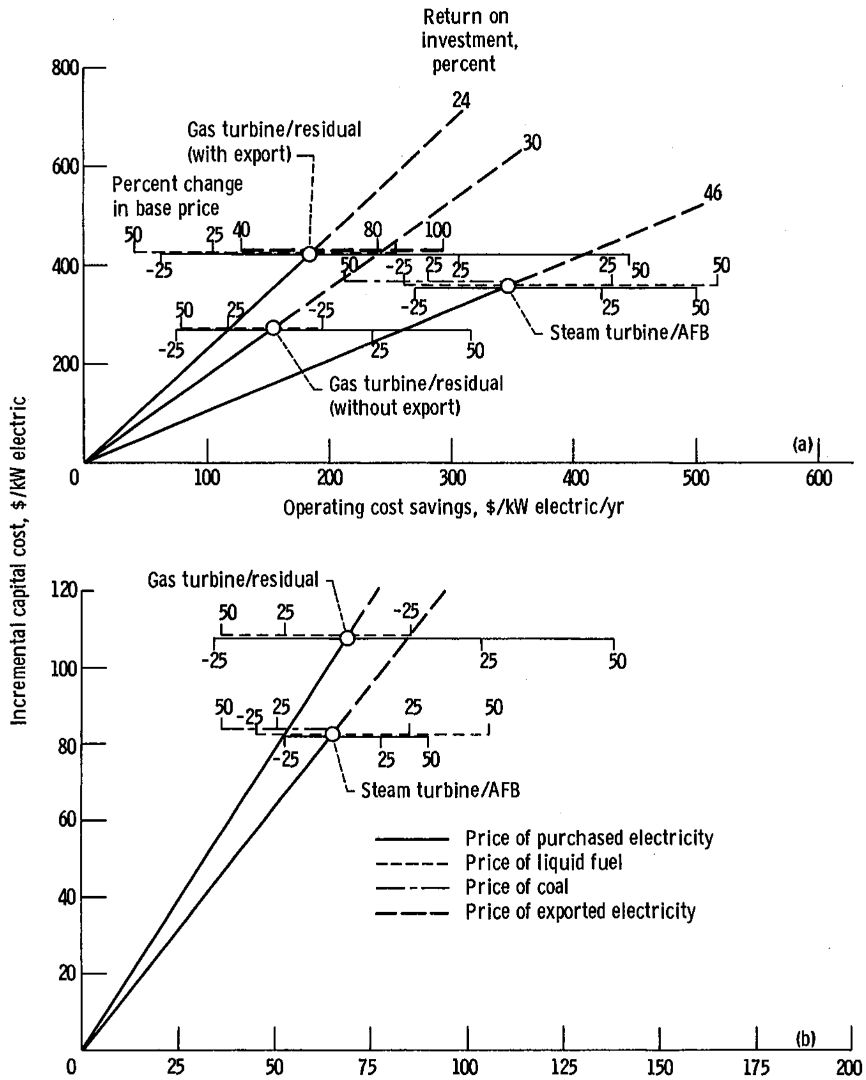
The effects of combinations of the changes shown in figure E-1(a) can be evaluated by vectorially adding the effects of the individual changes.

Figure E-1(b) diplays similar data for the chlorine plant, which has a higher power-to-heat ratio (1.55) than the writing paper mill. Again the liquid-fueled gas turbine and the steam turbine/AFB systems are used as example conversion systems. Note that, for the base case, again the steam turbine/AFB system yields the higher ROI. If the liquid-fuel price were assumed to be higher relative to coal and electricity than was assumed for CTAS, the advantage of the steam turbine/AFB system would be even greater. However, an increase of 25 percent or more in electricity or coal prices with no change in liquid-fuel price would result in the liquid-fueled gas turbine yielding the higher ROI.

As indicated earlier, the sensitivity results presented here are intended as examples, and the magnitudes of the changes shown apply only to the particular processes and systems specified. However, a few general trends from the broader sensitivity analyses performed should be noted:

(1) An increase in the assumed purchase price of electricity improves the economics of all of the cogeneration systems.
(2) Increasing the price of all energy (electricity and all fuels) does not significantly affect the relative comparison of systems.
(3) Changes in the relative fuel prices can significantly affect the relative comparison of systems that use different fuels.
(4) The attractiveness of export is highly dependent on the price received for electricity sold to the utility.
(5) Other economic variables showed lesser effects over the ranges studied.

The base fuel and electricity prices used in CTAS were based on national average prices provided by DOE. However, the relative fuel and electricity prices vary in different regions throughout the United States due to availability, transportation costs for fuel, etc. In many cases certain industrial processes are concentrated in particular regions because of the availability of raw materials, the availability of transportation, the convenience to the market place, etc. It is possible that in the region where a particular industry is concentrated, such things as fuel prices, electricity prices, and environmental restrictions may be much different from those assumed in CTAS. The Jet Propulsion Laboratory gathered data on regional characteristics throughout the United States that might affect the comparison of advanced cogeneration systems. A few cases were examined in CTAS to determine the of the effect of fuel prices in regions where selected industries are concentrated. The effect on the comparison of systems was small for the cases examined. However, a case-by-case study would be required to evaluate the impact of regional and/or local characteristics on the relative attractiveness of different advanced systems for specific applications. The information gathered by JPL on the regional concentration of industries and the regional characteristics are included in the NASA final report on CTAS.



(a) Writing paper mill.
(b) Chlorine plant.

Figure E-1. - Examples of sensitivity of cogeneration system economics to variations in fuel and electricity prices. (All values relative to noncogeneration boiler burning residual-grade, coal-derived liquid fuels and coal-fired utility.)

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16. Abstract
CTAS compared and evaluated various advanced energy conversion systems that can use coal or coal-derived fuels for industrial cogeneration applications. The study was sponsored by the Department of Energy (DOE). Project management of the overall effort was delegated to NASA's Lewis Research Center. Most of the data were developed under contracts with two industrial teams led by the General Electric Co. and the United Technologies Corp. In addition to study management Lewis also performed in-house analyses of the advanced systems. The Jet Propulsion Laboratory supported Lewis in selected areas. The principal aim of the study was to provide information needed by DOE to establish research and development (R&D) funding priorities for advanced-technology systems that could significantly advance the use of coal or coal-derived fuels in industrial cogeneration. Steam turbines, diesel engines, open-cycle gas turbines, combined cycles, closed-cycle gas turbines, Stirling engines, phosphoric acid fuel cells, molten carbonate fuel cells, and thermionics were studied with technology advancements appropriate for the 1985-2000 time period. The various advanced systems were compared and evaluated for a wide diversity of representative industrial plants on the basis of fuel energy savings, annual energy cost savings, emissions savings, and rate of return on investment (ROI) as compared with purchasing electricity from a utility and providing process heat with an on-site boiler. Also included in the comparisons and evaluations were results extrapolated to the national level. This report details the results of the CTAS effort, including the contractors' and Lewis in-house results.

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